U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	50-461/96010 (DRP)
Licensee:	Illinois Power Company
Facility:	Clinton Power Station
Location:	Route 54 West Clinton, IL 61727
Dates:	September 5 through October 4, 1996
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EXECUTIVE SUMMARY

Clinton Power Station
NRC Inspection Report 50-461/96010 (DRP)

This inspection was performed to review the circumstances surrounding the failure of the "B" reactor recirculation pump seal while attempting to place the unit into single loop operations. The report covers a period from September 5 through October 4, 1996.

Operations

- Various steps for isolating the "B" reactor recirculation loop were performed contrary to the procedural requirements.

- Although management entered the emergency plan when leakage exceeded 5 gallons per minute, the reactor shutdown was delayed even though leakage was greater than 10 gpm for 2.5 hours following the seal failure.

- An alert was not declared even though operators knew the seal had failed, knew leakage from a failed seal could exceed 50 gpm, and did not know what actual leak rate was. Additionally operations personnel did not fully understand what leakage conditions constituted entry into an Alert classification due to a lack of training.

- Tracking of identified leakage was not performed at any time during the event. This complicated the licensee's ability to evaluate the condition necessary for proper emergency action level classification.

- Allowing the suppression pool level to reach a level where an emergency operating procedure entry condition was required demonstrated poor monitoring of overall plant conditions.

- Operators were hampered in identifying the unidentified leakage source due to a number of long standing main control room deficiencies which had not been resolved.

- Following unit shut down, management was slow to address the control room deficiencies that complicated the identification of the leakage source until questioned by the NRC.

- Operators did not understand the limitations of LD-027 due to training inadequacies. Because of this, unidentified leakage was not monitored for 30 minutes following the seal failure.

- To reduce downtime and expedite unit restart, operators manipulated the feedwater system in a manner outside of the approved procedural guidance for long cycle cleanup operations. This procedural non-compliance caused the feedwater pump to be rotated without forced lubrication.

- Even though an estimated date for single loop operations was known, additional training for a newly formed crew was not given prior to the crew attempting to place the unit in single loop operations.

- The licensee's original self-assessment did not fully address the procedural compliance issues. These procedural non-compliances contributed significantly to the seal failure thus placing the unit in a less safe condition. In addition, several training deficiencies were not recognized. Extensive NRC intervention was necessary to obtain an acceptable evaluation.

Engineering

- The evaluation of the A & B reactor recirculation pump seal conditions following the April 9 scram did not fully consider all available data and lacked engineering rigor.

- Operators did not identify the increase in safety relief valve leakage during the reactor shutdown. An evaluation of this anomaly was not performed until the inspectors questioned the licensee.

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Overview of Event

On September 5, 1996, the licensee began actions to place the reactor in single loop operations by isolating the "B" reactor recirculation (RR) loop. The licensee believed that seal leakage from the "B" RR pump was causing the unidentified reactor coolant leakage to increase; isolating the pump might reduce the leakage. Power reduction commenced at 1805 hours in preparation for securing the "B" RR pump. At 2009 hours, the "B" RR pump was secured and the pump discharge valve was closed. Power level was decreased to 58%. Approximately forty-five minutes later, as a result of procedural non-compliances, unidentified drywell leakage exceeded the technical specification (TS) limit. Operations personnel entered the limiting condition for operation (LCO), 4 hours to reduce leakage or shutdown the reactor, and declared an Unusual Event for unidentified leakage greater than 5 gallons per minute (gpm).

Operations then shut the pump suction valve. Since the licensee believed that seal injection flow to the RR seals was contributing to the amount of unidentified leakage, and parameters indicated that the loop would not depressurize with seal injection flow lined up, a decision contrary to procedural and vendor guidance, was made to isolate the seal injection flow. Twenty-three minutes later the seal failed as indicated by rapid depressurization. The drywell floor drain leak rate was later calculated by the licensee to have peaked at 38 gpm. Following the depressurization, unidentified leakage decreased to approximately 10.5 gpm. During this time, the licensee continued actions to reduce leakage below 5 gpm.

At 0055 hours on September 6, 1996, the four hour LCO time expired. Since leakage was still greater than 5 gpm, the licensee was required to begin preparations for shutting down the plant. However, power reduction was not commenced until 0228 hours; the unit was placed in Mode 3 and Mode 4 at 1206 hours and 2316 hours respectively. The unusual event was terminated at 2150 hours on September 6, 1996, when unidentified leakage consistently remained below the TS limit.

I. Operations

01 Conduct of Operations

01.1 Preparations for Entering Single Loop Operations

a. Inspection Scope (71707)

The inspectors reviewed the licensee's preparations for entering single loop operations. In addition, the inspectors monitored activities in the control room that were performed prior to transitioning into single loop operations.

b. Observations and Findings

In mid-August, the licensee performed an analysis to estimate the best time for replacing the "B" RR seal prior to refueling outage-6 (RF-6). The analysis

considered the estimated energy demands for the period, reactor safety, and fuel burnup concerns. Results showed that if conditions warranted, a shutdown to replace the seal prior to mid-September would have been more economical than operating the reactor in single loop until refueling outage number 6 (RF-6), scheduled to begin on October 13, 1996.

A 0.6 gpm step change in unidentified leakage was observed during the week of August 26, 1996. Although licensee management became more focused on trying to identify the source of the leakage, the leakage leveled out over time and a plant shut down was averted. The unexpected change in leakage prompted licensee management to set an administrative limit of 4 gpm unidentified leakage. Upon reaching the administrative limit, the licensee would enter single loop operations and attempt to identify the leakage source. If isolating the "B" reactor recirculation loop reduced the leakage, the licensee planned to consider operating in single loop until RF-6. However if the actions taken to reduce leakage were unsuccessful and leakage exceeded 5 gpm, TS required a plant shutdown.

In early September, one of Illinois Power's (IP's) fossil units was also experiencing operational difficulties. The load dispatcher, prior to September 5, requested that Clinton Station (CPS) try to transition into single loop operations because the outcome of this evolution would directly effect power availability for the IP electrical distribution system and a planned maintenance outage at one of IP's fossil units. If single loop operation was achieved IP would be able to take the fossil fuel unit off-line for needed repairs. In addition, the Assistant Director-Plant Operations told the inspectors that he concurred with the position to proceed to single loop to prevent thermal cycling the plant during shutdown activities. The Assistant Director-Plant Operations believed that a thermal cycle could have adversely impacted degraded equipment scheduled to be repaired during RF-6; further degradation of this equipment may have effected the timeliness of the subsequent reactor startup.

Engineering personnel estimated that the plant would exceed 4 gpm unidentified leakage on approximately September 6; however, seal deterioration accelerated and leakage increased to between 3.8 and 4.1 gpm one day earlier than expected. On September 5, the Assistant Director-Plant Operations developed new guidelines for the RR loop isolation and for the evaluation of unidentified leakage. The guidance contained three possible courses of action which were dependent upon the amount of leakage experienced once the loop was isolated. The guidance was as follows:

- If floor drain leakage remained unchanged, the operation's department was to consider isolating the reactor water cleanup (RT) system from the RR loops to determine if valve 1G33-F106 was leaking. Maintenance work request D34974, dated February 10, 1993, documented a suspected packing leak on this valve. If this failed to decrease leakage then licensee management was to decide the next course of action.

- If leakage decreased, then a management decision on continuing operation in single loop was to be made.

- If the leakage exceeded 4.5 gpm, then operations was to continue to shut down the plant and go to Mode 4.

The inspectors review of this guidance document determined that the document had not received an independent technical review. CPS 1005.01, "CPS Procedures and Documents," Step 8.4.9.1, states that "all procedures and documents shall be reviewed by an independent technical reviewer." The failure to have the document independently reviewed is an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," (EEI 50-461/96010-01a).

The operations briefing for isolating the "B" RR loop was detailed and covered a number of scenarios which could have occurred once actions were taken to isolate the RR loop. Operations personnel discussed potential transients including a catastrophic seal failure and a reactor scram. The crew was assured by the system engineer that the seal would not be significantly affected by the transition to single loop. Little was addressed concerning increasing leakage as the crew expected that closing the loop isolation valves would stop any leakage from the loop. The procedure for manipulating control rods was also reviewed since it was necessary to reduce reactor power prior to isolating the loop.

Control rod manipulations were well planned and a nuclear engineer was present during this time to assist the crew as needed. The reactor operator and second verifier remained focused on properly selecting rods prior to movement. After power was reduced to approximately 69%, the operations crew began actions to isolate the "B" RR loop (see Section O1.2).

c. Conclusions

The operators performed the initial actions for transitioning into single loop operations in a controlled manner. The nuclear engineer provided appropriate coverage during the power reduction and sound advice during the pre-evolution brief. However, the Assistant Director - Plant Operation's emphasis on actions extending the scheduled outage may show an inappropriate emphasis on outage schedule. The inspectors were also concerned that pressure may have been applied to achieve single loop operation to support a fossil fuel unit maintenance outage.

O1.2 Isolation of the "B" Reactor Recirculation Loop and Plant Shutdown

a. Inspection Scope (71707/93702)

Once the licensee made the decision to proceed with transitioning to single loop operations, the inspectors monitored the licensee's progress by directly observing activities in the control room.

b. <u>Observations and Findings</u>

Isolation of an idle RR loop was governed by CPS 3302.01, "Reactor Recirculation," Section 8.2.4. Following securing the RR pump, operators proceeded with isolating the loop under "normal" conditions. The loop discharge valve was shut and the RT suction valve from the "B" RR loop was closed in accordance with the procedure. The procedure stated that under "normal conditions," the idle loop should be allowed to cool down to less than 250°F prior to securing seal injection flow and shutting the RR suction valve. A control room operator performed a quick calculation which showed that at least six hours would be needed to cool the idled loop below 250°F. Management then directed the control room operator to shut the seal staging flow valve in an effort to enhance the loop cooldown. The closing of the seal staging valve at this time did not follow the sequence delineated in the procedure. Within 25 minutes, unidentified leakage increased from 4.22 to 5.52 gpm.

CPS 1005.14, "Formatting of Procedures and Documents," Step 8.1.11.4, states that if a specific order of performing the procedure is required, an asterisk (*) should be placed at the beginning of the section to annotate that the steps are to be performed in the sequence they are written. CPS 3302.01, "Reactor Recirculation," Section 8.2.4, had an asterisk at the beginning of the section. The failure to perform the procedure in the order written is an apparent violation of TS 5.4.1, "Procedures," (EEI 50-461/96010-02a).

An Unusual Event was declared due to unidentified leakage greater than 5 gpm. In addition, the appropriate TS LCO was entered which allowed four hours to reduce the leakage to less than 5 gpm. CPS 4001.01, "Reactor Coolant System Leakage," was also entered due to the abnormal leakage condition. The licensee identified that CPS 4001.01, Step 4.4, directed the control room staff to notify radiation protection to help in the identification of the source of leakage. This was not performed. The failure to perform this step of the procedure is an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," (EEI 50-461/96010-01b).

Operations personnel then entered step 8.2.4.3 of CPS 3302.01 which delineated the steps for isolating an idle RR loop under "emergency" conditions. The pump suction valve was closed at 2130 hours; however, closing the seal staging shutoff valve was not necessary since it was closed earlier in the evolution. Within thirty minutes, the leakage rate had increased to approximately 6 gpm.

Under "emergency" conditions operations personnel were instructed by procedure to allow the RR loop to cool to 250°F prior to securing seal injection. In the event the RR seals were failed (indicated by the loop being depressurized to approximately drywell pressure), seal injection flow could be secured. It should be noted that the seals were not failed at this time.

The procedure cautioned that securing seal injection flow prior to reaching a reactor coolant system loop temperature of 250°F would result in seal cavity temperatures reaching 185°F within 30-60 minutes. In addition, the caution stated that seal damage would occur at a cavity temperature of 250°F. The time necessary to reach 250°F was dependent upon the seal leakage rate and initial cavity temperature. It was previously determined that the loop temperature would not have been less than 250°F for quite some time. In addition, this temperature may have never been reached due to apparent seat leakage through the pump suction or discharge valves.

With the loop isolated and the RR seal leaking, the loop should have depressurized. Management believed that seal injection flow from the control rod drive (CRD) system was maintaining the loop pressurized and contributing 3-5 gpm to the total unidentified leakage. Management then directed the closing of the seal injection valve (1C11-F026B) to try and decrease unidentified leakage. This was not in accordance with the sequence of steps given in the procedure. At the time the seal injection flow was secured, the "B" reactor recirculation loop temperature was approximately 490°F.

The closing of the seal injection valve was a second example of procedural steps not being performed in sequence for a procedure section proceeded by an asterisk (CPS 3302.01, section 8.2.4). The failure to perform the procedure in the order written is an apparent violation of TS 5.4.1, "Procedures," (EEI 50-461/96010-02b).

Approximately 23 minutes after seal injection flow was secured the "B" RR seal rapidly depressurized from 950 psig to 280 psig. Drywell pressure increased and drywell cooler drain flow increased to 3.5 gpm. Unidentified leakage also increased; however, due to confusion on how the drywell floor drain instrument worked, the operating crew failed to obtain appropriate leak rates for approximately 30 minutes following the seal failure (see Section O1.3). Engineering personnel later determined that seal cavity temperatures exceeded 400°F following isolation of the seal injection flow.

From 2222 hours to 0055 hours, the operations staff performed actions in an effort to reduce unidentified leakage. The RT system was double isolated at 0030 hours to prevent any leakage from the RT suction valve for the "B" RR loop. At 0055 hours, the LCO time clock expired and the control room operators began to review the appropriate procedures for shutting down the plant. At 0200 hours, a shutdown briefing was held and power reduction began at 0228 hours.

Between 0228 hours and 0310 hours reactor power was reduced from 55% to 38%. CPS 3005.01, Step 6.1.b, requires that a gaseous sample be taken when thermal power changes exceed 15%. Although power had been reduced by 17%, the licensee identified that a gaseous sample was not obtained

due to operations failure to notify the chemistry department. This is an additional example of an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" (EEI 50-461/96010-01c).

During the event, the inspectors observed licensee management and the shift supervisor directing activities in the control room rather than remaining in a monitoring role. CPS 1401.01, "Conduct of Operations," Step 8.3.3.1, states that "the shift supervisor should **report to the control room and remain in a monitoring role** during off normal operation unless the shift supervisor determines that the line assistant shift supervisor is not able to deal with the situation. This is an extraordinary situation, and it is expected that in all but extreme cases the shift supervisor will remain in the monitoring mode." The failure of the shift supervisor to remain in a monitoring role during the event was an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," (EEI 50-461/96010-01d).

No additional difficulties were encountered with the shutdown until 0612 hours when a fire was reported in the service building basement computer room. A fire brigade composed of 6 members responded to the scene and determined that no fire existed only light smoke from a failed computer power supply.

During this same time, suppression pool (SP) water level was approaching the TS limit of 19 feet 5 inches. One source of water entering the pool was due to leaking safety relief valves (SRV). The leakage from these valves was approximately 5000 gallons per day (inspection report (IR) 96006 section O1.1) and had been leaking since the April 9, 1996, scram (IR 96004). The major source of water entering the SP was due to flushing a cycled condensate header located in the containment. Mechanical maintenance had been flushing the header in preparation to replace the RR "B" seal. The flush was adding approximately 50,000 gallons per day to the SP.

Since the scram on April 9, operators had been controlling SP level between 19 feet and 19 feet 4 inches to work around the SRV leakage and minimize the number of times SP cooling was used to lower the water level. At 0623 hours, SP water level reached 19 feet 5 inches. Although the crew was originally aware that SP level was approaching the limit, the reported fire and required response distracted the operators.

At 19 feet 5 inches, the SP level alarm annunciated. In addition, this level was also the entry condition for TS LCO 3.6.2.2 for SP level and entry into Emergency Operating Procedure (EOP) CPS 4402.01, "Primary Containment Control." Having the same SP level for an alarm point, an entry point for an LCO, and an entry condition for an EOP appeared to place an inappropriate burden on the operators. Furthermore some instrumentation in the control room provided the operators with confusing data. For example, while the TS and EOP entry condition call out 19 feet 5 inches, the video display of important plant parameters reads out as decimal (such as 19.4 feet) instead of in feet and inches.

A late control room log entry identified the entry into the EOP; however, no log entry for entering the LCO was made. The shift supervisor's log also had no entry concerning the event. CPS 1401.01, "Conduct of Operations," Step 8.4.4.10, states that "significant plant operating data, such as abnormal plant conditions, should be entered in the shift supervisor and main control room journals." The failure to document entry into a limiting condition for operation is an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" (EEI 50-461/96010-01e).

At 0945 hours an operator made an error during the transfer of electrical busses from the unit auxiliary transformer to the reserve auxiliary transformer. The operator mistakenly turned a control switch past the neutral position when returning the switch from the closed position. His actions caused the B circulation water pump to trip, the RT "B" & "C" pumps to trip, the "A" electrode boiler to trip, the stator water cooling pump "A" to auto start, the turbine bearing lift pumps to auto start, and the reactor protection system solenoid inverter "B" to alarm. The operator was quick to acknowledge his error. However the error delayed the plant shutdown which then continued without any additional problems.

c. Conclusions

The initial steps of procedure 3302.01, "Reactor Recirculation," were performed as written. However, as leakage increased and exceeded the TS limits, management directed the performance of actions contrary to the procedure which directly contributed to the seal failure. The inspectors were concerned about the long delay in commencing the power reduction and that the normal shutdown procedures had not been reviewed prior to starting the evolution. This would have expedited the ability to shut down the plant.

As discussed in a previous report (IR 96006, section O2.1) the aggregate of control room deficiencies placed additional burden on operators. The suppression pool water level problem due to leaking SRVs, in conjunction with the CY flush, placed operators in a difficult situation. During the plant shutdown and having to respond to a fire, operators failed to adequately control the suppression pool water level.

The licensee's non-conservative approach to operations contributed to several procedure violations.

O1.3 Declaration of Unusual Event

a. Inspection Scope (71707)

The inspectors evaluated the licensee's emergency preparedness response to an unidentified leakage rate over five gpm and the subsequent failure of the RR pump seal.

b. Observations and Findings

The inspectors observed that proper notifications of the Unusual Event were made on site and off site to state, local and NRC officials. Inspector review of applicable emergency response procedures determined that the declaration of an Unusual Event was appropriate.

As previously stated, the control room responded to an increase in unidentified drywell leakage to over five gpm by declaring an Unusual Event. This declaration was made within 15 minutes of identifying the condition. Following the subsequent reactor shutdown and cooldown, unidentified leakage dropped to less than 5 gpm and the licensee exited the Unusual Event.

The inspectors reviewed the applicable Emergency Action Procedure (EAP) entrance criteria and determined that the appropriate Emergency Action Level (EAL) was entered. However, the inspectors were concerned that the licensee did not know total reactor coolant system (RCS) leakage (unidentified plus identified RCS leakage) immediately following the RR pump seal failure. The inspectors determined that identified leakage was not being tracked and unidentified leakage was not immediately known due to the failure to understand equipment limitations (see section O4.1). Considering that the Updated Safety Analysis Report, Appendix D, Section II.K.3.25, states concerning RR seal failure, "... the primary coolant loss is analyzed to be less than 70 gallon per minute," operators should have been more sensitive to the potential of reaching an Alert condition. The EAPs stated that an Alert must be declared if total RCS leakage exceeds 50 gpm. On September 5, the operators knew that the seal had depressurized, and failed, and did not know what total leakage was. A proper response to these condition would have been to declare an alert status to ensure proper licensee and regulatory attention was given to the situation.

On the following day, the inspectors discovered that the licensee was not tracking identified leakage during the event. At the inspectors request, the licensee finally performed the required calculations and determined that the Alert criteria of 50 gpm had been not exceeded (highest total leakage was 48 gpm).

CPS 1401.01, "Conduct of Operations," Step 8.1.6.2a, states that "during off normal conditions one of the primary duties of the STA is to assist the shift supervisor in the identification of the proper emergency action level classification. The lack of evaluating conditions both during and following the event, specifically within the first 30 minutes following the seal failure, in order to monitor possible entry into an emergency classification condition is an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings" (EEI 50-461/96010-01f).

Because the margin below 50 gpm was small, the inspectors reviewed the relevant data and independently performed calculations to determine identified and unidentified leakage rates. The licensee's calculations were determined to be valid and conservative.

On September 6, the inspector noted a lack of knowledge by operations personnel concerning what constituted RCS leakage greater than 50 gpm as listed in the EAPs for an Alert status. At the request of the inspector, the training department reviewed the lesson plans. Neither initial operator training nor requalification training taught the operator that identified leakage and unidentified leakage must be added together to determine if an Alert condition existed. The inspectors considered this to be a significant weakness in the operations training program.

c. Conclusions

While the licensee properly exercised the emergency response procedures to declare an Unusual Event when unidentified reactor coolant leakage exceeded five gpm, given the known seal condition, the lack of accurate leak rate data, and the potential leak rate from a failed seal an Alert should have been declared.

Poor operator performance was exhibited, caused by a lack of knowledge, in using leak detection equipment and tracking total RCS leakage rates for applicability toward the emergency plan. In addition, training concerning the Alert entry conditions for RCS leakage was inadequate.

02 Operational Status of Facilities and Equipment

02.1 Determination of Leakage Source Difficult Due to Equipment Deficiencies

a. Inspection Scope (71707)

Control room operators encountered difficulties in verifying that the degraded recirculation pump seal was the only source of unidentified drywell leakage due to conflicting indications in the control room. The inspectors interviewed operations personnel that were on shift during the event and reviewed the following documents:

- Shift Supervisor Logs
- Reactor Operator Logs
- "Guideline for RR B Loop Isolation and RF Leakage Evaluation" provided to the Shift Supervisors by the Assistant Director-Plant Operations.
- Engineering Guidance provided to Operations "RR Pump 'B' Seal Degradation" dated August 2, 1996

b. Observations and Findings

Since startup following the April 9 scram, the "B" RR pump outer seal pressure decreased to approximately 240 psig which indicated that the outer seal was degrading. The outer seal pressure then began to increase which was indicative of inner seal degradation. Over time, the outer seal pressure increased and leveled out near the normal outer seal pressure of approximately 500 psig. The changes in seal pressure were as predicted by plant engineering based on data from several other RR seal degradations at Clinton.

Although the changes in seal pressure were symptomatic of deteriorating RR pump seals, the operators were not certain that the seals were the sole contributor to the increase in unidentified drywell leakage. The confusion was related to conflicting and missing information.

- The pump seals have two seal leakage alarms which could have removed some uncertainty. The "outer seal leakage HI" alarm has had a maintenance work request written since May 14, 1995, due to repeated false alarms (up to 30 alarms per hour). The annunciator actuated soon after the April 9th scram and remained lit. Operators were uncertain if the annunciator was indicating a problem or had failed again.

  The other alarm, "seal staging flow HI-LO," did not activate until operators secured flow to the instrument. Engineering guidance to operators was to expect this alarm as the seals degraded due to low flow condition to the instrument. The lack of the annunciator added to conflicting indications given to the operators. In addition, the inspectors identified that the annunciator response procedure (CPS 5003.05) for this annunciator provided misleading information under the operator actions section. The procedure stated that a failure of both seals would cause the alarm due to HI flow to the instrument.

- Operators isolated different potential leakage paths in an attempt to identify the source of the leakage. Since the drywell floor drain sump flow (v-notch) instrument had been inoperable for most of the cycle, the operators were unable to obtain real time changes in unidentified leakage. Instead, operators had to wait for the sump pumps to cycle two times (approximately 3 hours) before any changes could be identified using a recent modification that supplies an alternate means of monitoring leakage (LD-027). While this method was acceptable, it did not provide timely trending data of the changes.

- Several points on the valve stem seal leakoff recorder, for leak detection, were inoperable. The inoperable points included the B RR pump suction and discharge valves and the RT loop isolation valve. These valves had been stroked as part of the recirculation loop isolation process and the shift supervisor's concern was that the stem leakoff may be adding to the leakage being attributed to the pump seal.

  The inspectors reviewed the maintenance history and found ten maintenance work request tags hanging from the recorder. The oldest tag was dated February 19, 1992. This deficiency had not been corrected because a full core offload was needed to complete the necessary repairs. The licensee indicated that 8 of the 10 deficiencies would be repaired during RF-6.

- Another confusion factor was that pump seal temperatures decreased as unidentified leakage increased. The expected response was for seal temperatures to increase with the increased leakage. In addition, the seal cavity heat exchanger component cooling discharge line indicated 11°F hotter than the seal water it was cooling. From a thermodynamic standpoint, this was not

possible. The licensee independently checked the three resistance temperature detectors before the seal failure and confirmed that the meter readings were accurate for the signals from the field. (Following the event, engineering concluded the most likely cause of the lower temperatures was that the seal leakage was externally cooling the thermocouples).

- Prior to the September 5, 1996 event, data from the v-notch indication system for the drywell equipment drain sump remained constant while values calculated from sump pump run times continued to increase. Operators declared the v-notch instrument inoperable on August 26, 1996. Problems were also encountered due to flow rates associated with the sump pump run times. Using a portable flow detector, plant engineers promptly determined that the sump pump check valves were allowing backflow through the system and thereby effecting the leakage calculations. Plant engineers provided operations with an alternate means of calculating identified leakage to compensate for the leaking check valves. The engineers also checked for backflow on the drywell floor drain system and found no problems.

Approximately a week prior to the September 5 event, operations and engineering recognized that if unidentified leakage approached the TS limit (greater than 5 gpm) that the available instrumentation might not be adequate to verify TS compliance. Since the drywell floor drain v-notch system was inoperable, real time indication of changes in leakage was not available and the LD-027 system only provided data with each sump pump cycle. The TS allowed 4 hours to reduce leakage within the limits. The challenge to engineering was in verifying that actions taken to isolate the leakage were within the time allowed.

Well before the TS limit was reached or single loop operation was attempted, plant engineering provided operations with clear guidance on how to work around the normal operation of LD-027. By forcing the sump pump to operate on the low level float switches, the pumps would run more frequently and the time required for LD-027 to update would decrease. Operations placed the system in the suggested configuration days before attempting single loop operation and the system performed as expected.

Inspection report 96006, dated July 29, 1996, discussed that the tolerance of degraded equipment had been an NRC concern since the last Systematic Assessment of Licensee Performance period (November 28, 1993 through June 24, 1995). Although the licensee had placed renewed emphasis on resolving a number of control room deficiencies, the deficiencies that remained significantly hampered the operators in determining the unidentified leakage source. The licensee's original plan was to restart the reactor prior to addressing the deficiencies discussed above. This decision was re-visited when the inspectors raised concerns.

c. Conclusions

Operations was placed in a difficult position due to inoperable or unreliable indications in the control room.

04 Operator Knowledge and Performance

O4.1 Operator Knowledge of Plant Equipment and Instrumentation

a. Inspection Scope (71707)

The inspectors interviewed operations personnel that were on shift during the event and reviewed the following document:

- Review of requalification training records concerning the LD-027 including RC92014-00, RECENT PLANT MODIFICATIONS - CYCLE 95.3

b. Observations and Findings

During the event, LD-027 was used to provide indication of the unidentified leakage rate. Once the seal failed and leakage exceeded 5 gpm, the indication for LD-027 pegged high. The operations crew did not initially recognize that LD-027 provided inaccurate information for flow rates above 8 gpm even though the monitors in the control room displayed "white data" (which signified the information was inaccurate). It was not until the oncoming shift technical advisor (STA) entered the control room at 2248 hours and reminded the on shift STA that manual leakage calculations were needed, since LD-027 was inoperable for flows above 8 gpm, that leak rates were calculated.

This lack of knowledge by the operations crew resulted in an approximately 30 minute delay in providing actual leakage data to the shift supervisor during a significant time in the event. Flows had actually peaked at 38 gpm and had decreased to approximately 15 gpm prior to the shift supervisor being notified.

During interviews, most shift personnel indicated that they were either unfamiliar with or had forgotten the limitations of LD-027 if trained earlier. Training on LD-027 occurred in May 1995 prior to its installation in the plant. In discussions with the system and design engineers, the inspectors learned that during the LD-027 design process a determination was made to clamped the indication at 8 gpm. However in discussions with training personnel, the inspectors were told that the LD-027 modification was reviewed for possible training impacts prior to design completion. This early review resulted in the failure to communicate the full limitations of the instrument.

c. Conclusions

Although the crew demonstrated knowledge of plant equipment in most areas, the need for training in other areas was apparent. The failure of the training staff to provide instruction on the full limitations of LD-027 was a weakness and contributed to the delay in performing manual leakage calculations following the seal failure.

O4.2 Inadvertent Windmilling of the Motor Driven Feedwater Pump

a. Inspection Scope (37551)

The inspectors reviewed activities related to the inadvertent windmilling of the motor driven feed pump (MDFP). This was identified by the licensee and documented in a condition report.

b. Observations and Findings

Description of Event

After a transition to "long cycle" cleanup from "short cycle", the operations shift recognized that cleanup efforts were slowed due to the unavailability of a large return valve (1FW021) to the condenser. The shift determined that in order to obtain greater feed system flow rates and resulting faster cleanup times the MDFP minimum flow valve could be opened to obtain a parallel return path from the feed system to the condenser. Once the valve was opened, the MDFP was inadvertently windmilled for about 12 hours. This condition was recognized by an equipment operator (EO) conducting his tour. The EO subsequently started the auxiliary lube oil pump to provide proper lube oil flow to the pump.

Initial Inspector Followup

The inspector questioned the line assistant shift supervisor (LASS), the EO who discovered the MDFP windmilling, and other operations personnel to determine the procedural justification for opening the minimum flow valve.

Personnel questioned could not initially provide any operational or administrative procedure reference that provided guidance for opening the minimum flow valve. Operations support personnel conducted an electronic word search in the procedure database and reported that no guidance could be found that allowed operators to operate equipment outside of the guidance of a procedure. They added that only the temporary modification process or the temporary procedure change process appeared to apply. Neither of these processes were used.

The LASS, however, indicated that he felt he had the authority to conduct simple equipment operations as long as a reduction in safety or harm to equipment did not occur.

Operators Subsequently Provide Procedural Guidance

The next day, the LASS and operations support personnel provided the inspector with documentation that was discovered by the LASS **after** the initial questioning by the inspector was complete.

This documentation included section 8.1.6 of the feedwater procedure (CPS no. 3103.1, rev 13) which addressed operation of the feed pump minimum flow valves and a plant manager's standing order (PMSO-043 dated 7/9/96) that addressed verbal instructions to conduct operations.

Section 8.1.6 of the feedwater procedure was a stand alone section that apparently was previously not known to exist by the EO and the LASS when initially questioned. It had a note which indicated that the LASS could direct that ROs take manual control of reactor feed pump (RFP) minimum flow valves during RFP start up and low feed flow conditions. The LASS stated, when originally questioned, that this section was applicable during long cycle cleanup because the feedwater system was in a low flow condition, and that the authority for opening the minimum flow valve was in accordance with this procedure.

However, inspector evaluation of section 8.1.6 determined that the implied purpose of this section was to protect **operating** feed pumps from overheating during feed pump operation. Otherwise, guidance should have been provided to take actions to provide lubrication to windmilling feed pumps. During long cycle cleanup, the feed pumps do not operate.

Applicability and Adequacy of a Plant Manager Standing Order

PMSO-043, "Verbal Instructions to Conduct Operations," established the circumstances by which management could provide verbal instructions for conducting operations. In addition, the associated documentation that was required to support those verbal instructions was discussed. The PMSO gave permission to the Director of Plant Operations, among others, to expeditiously perform simple operations that were not prohibited, but also not specifically outlined in existing procedures. It stated that providing verbal authorization provided the flexibility to expeditiously determine problems. Examples of such evolutions were provided such as valve stroking for operational checks, re-positioning of control switches to check for operation, and cycling of circuit breakers to verify operation.

PMSO-043 included the requirement to document the verbal instruction into the appropriate organizational log and listed occasions for which verbal instructions were not applicable. Instances of inapplicability included:

- complex evolutions;
- control rod motion outside of sequence;
- evolutions that would cause operational limits to be exceeded;
- evolutions that would, by duration, cause a mode change due to entry into an LCO action statement.

The inspectors determined that PMSO-043 was not applicable for the positioning of valves to a new position. Additionally, it was not clear that the delegation of authority extended to the LASS.

Also, PMSO-043 conflicted with the conduct of operations procedure (CPS No. 1401.01 rev 24). Section 8.4.1.1 of procedure 1401.01 stated that CPS shall be operated in accordance with approved and issued procedures during all modes of operation. The standing orders and night orders procedure (CPS No. 1005.05 rev 13) section 6.1, stated that standing orders shall not conflict with or change an approved procedure. Therefore, the PMSO conflicted with the conduct of operations procedure in that it allowed the operation of plant equipment outside of the scope of a formal procedure.

Consequently, the inspectors were concerned over the acceptability and adequacy of having a standing order authorize the manipulation of the plant outside of the scope of plant operational procedures. It is also unclear as to the extent that delegation of authority can transfer from the Director of Operations to the LASS.

Lack of Knowledge of Administrative Control Procedures by Operations Personnel

The inspectors questioned both the "A" and "B" reactor operators (RO) involved in the opening of the minimum flow valve to determine their thought process.

The ROs were not aware of the procedural guidance in section 8.1.6 of the feedwater procedure. In addition, the ROs acted under the perception that the LASS had the authority to provide direction on the operation of equipment outside of plant procedures as long as plant safety was not compromised. They did not indicate knowledge of the specifics of PMSO-043, but did indicate that a log entry would need to be made. The log entry would be carried forward in the logs to indicate configuration of plant equipment for informational and turnover purposes.

A review of the RO log showed that no log entry had been made to indicate the opening of the minimum flow valve. Although PMSO-43 required a log entry to be made, the inspector determined that PMSO-43 was not applicable to the situation. However, CPS 1401.01, "Conduct of Operations," Step 8.4.4.10e, requires all abnormal plant conditions to be logged in both the shift supervisor and main control room logs. The RO who was responsible for log keeping admitted that he should have made the log entry. The failure to document entry into an abnormal plant condition is an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" (EEI 50-461/96010-01g).

Potential Damage to the MDFP

The inspectors were concerned about the potential damage incurred to the MDFP when it was windmilled for about 12 hours without the auxiliary lube oil pump in operation.

Windmilling of a pump is acceptable only if the pump receives proper lubrication. In the case of the MDFP, it had an associated shaft driven lube oil pump that provided total pump lubrication at normal operating speeds. However, the auxiliary lube oil pump was designed to provide lube oil flow to the feed pump until the shaft driven lube oil pump reached a speed that would provide sufficient oil flow.

In this case, the operators failed to ensure that the auxiliary lube oil pump was running, and potentially caused damage to the pump. The results of a subsequent lube oil analysis showed no evidence of pump damage.

Improper use of the Feed Pump Minimum Flow Valves was an Isolated Case

Because the degradation of the large return valve may have caused the licensee to deviate from the long cycle cleanup procedure in the past, the inspectors performed a review of previous long-cycle operations.

The system engineer indicated that during the previous refueling outage, the large return valve was used for long cycle cleanup and subsequently declared inoperable due to valve and motor degradation. An outage to replace the B RR seal package was conducted in December 1995 which required establishing long cycle cleanup prior to returning to power operations. The cognizant reactor operator was interviewed and the logs were reviewed to determine if a feed pump minimum flow valve was opened to increase the long cycle feed flow. The inspector concluded, that the long cycle procedure had been adhered to, and that the feed pump minimum flow valves had not been opened.

Material History Review of the Long Cycle Cleanup Return Valve

The inspectors were concerned that the material condition of valve 1FW021 had been known for some time and that the licensee was not taking timely action to repair the valve.

This valve was used during feedwater cleanup operations and was not a valve required for power operations or for plant safety. Its history included valve replacement prior to initial plant startup in 1985 due to severe erosion/corrosion, two burnt out motor operators that required replacement, and valve repair activities.

Apparently, the root cause of these failures was that the valve design was not suited to the application that it was subjected to. Following the last refueling outage (RF-5), the licensee planned to replace the valve, its bypass valve and some associated piping with a better design.

c. Conclusions

The inspectors were concerned that operators were not cognizant of existing operations administrative procedures and standing orders. In addition, the acceptability and adequacy of having a standing order authorize the manipulation of plant equipment outside of the scope of plant operational procedures was not clear

at the conclusion of the inspection. The licensee's efforts to justify operator actions with procedures that were unknown to the operators when the actions occurred was neither well thought out nor appropriate. If an operator is not aware of a procedure or PMSO prior to performing an action then, in the inspectors opinion, it is impossible to say that procedures were followed during the time in question.

The inspector concluded that opening the minimum flow valve to enhance long cycle cleanup was not in accordance with approved procedures. CPS 1401.01, "Conduct of Operations," Step 8.4.1.1, states that "CPS shall be operated in accordance with approved and issued procedures during all modes of operation." The operation of equipment outside of the procedural requirements is considered an apparent violation of 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures and Drawings," (EEI 50-461/96010-01h).

O5 Operator Training and Qualification

O5.1 Preparations for Single Loop Operations

a. Inspection Scope (71707)

The inspectors interviewed operations personnel that were on shift during the event and reviewed the following documents:

- "Guideline for RR B Loop Isolation and RF Leakage Evaluation" provided to the Shift Supervisors by the Assistant Director-Plant Operations.
- Training Seminar - RS91042-00 - EOP-6

b. Observations and Findings

Training in preparation for single loop operation consisted of each crew reading and discussing the applicable procedures. The contingencies necessary for seal degradation or failure were also discussed and the necessary off-normal procedures were identified.

Although the licensee had an estimate of when the plant would proceed to single loop operations, no simulator training specific to operating the reactor in single loop under normal conditions was requested by operations or performed by training. Operations personnel on shift during the event indicated that this was the first time they had transitioned to single loop and additional training would have been helpful. By reviewing the crew assignments, the inspectors discovered that the crew which performed the loop isolation was newly formed. In addition, the day of the event was the first time the shift supervisor had directed the actions of this crew compliment. It was not apparent that this newly formed crew had completed any training evolutions as a crew prior to performing the loop isolation.

One scenario, which was performed during the normal training cycle, included isolating an RR pump with a degraded seal while maintaining the plant on line; however, continued single loop operations was not explored. All crews received this scenario during the last training cycle which ended in mid-August 1996. Training personnel indicated that while the operations crews have received training on isolating an RR loop under transient conditions, isolation of the loop under normal conditions has not been performed for at least two years. Further, it is not known whether the scenario simulated progressive seal degradation and leaking recirculation isolation valves.

c. Conclusions

Tracking of the RR pump seal degradation provided early indication of the necessity for a shutdown in early September. However, the opportunity to provide a newly formed operations crew with additional simulator training specific to an infrequent operation was not taken.

O5.2 Additional Training Concerns

General Comments

While discussing the training given on LD-027 with the training staff, the inspectors became aware of additional concerns in the training area. Members of the training staff stated that operators were performing simulator scenarios with the drywell floor drain v-notch operable. This instrument was not operable during the event and has been inoperable since early 1996. In addition, the licensee has had difficulties maintaining this system in an operable status for at least three years. The inspectors were concerned that the licensee was conditioning the operators to use the v-notch under both normal and adverse operating conditions even though this instrument was rarely operable.

The training staff also indicated that while the monitors in the control room display "white data" (indicating invalid information) when LD-027 exceeds 8 gpm, the monitors in the simulator do not. This deficiency provides the operator with false indication since a point which is not displaying "white data" is assumed to be indicating properly.

Another training issue was discussed in Section O4.1.

O7 Quality Assurance in Operations

O7.1 Review of Licensee's Assessment and Corrective Actions

a. Inspection Scope (40500)

The inspectors reviewed the licensee's initial self-assessment of the event and the proposed corrective actions to determine if all the concerns related to the event were adequately addressed.

b. Observations and Findings

During this inspection, the inspectors identified examples where activities were performed contrary to the current procedural requirements. Because of this concern, the licensee was prompted by the NRC to perform a self-assessment of the activities related to the seal failure.

Prior to issuing the assessment report, the Vice President-Nuclear sent a preliminary assessment letter to the Regional Administrator on September 12, 1996. This letter stated that, "We (CPS) were not conservative in our operation of the unit. Lack of a conservative approach to procedure interpretation led to failure to comply with procedures."

On September 16, 1996, the Nuclear Assessment Department (NAD) released the results of their self-assessment of the event. The cover letter attached to the assessment failed to identify the lack of procedural compliance as an issue which contributed to the event even though four days earlier the Vice President viewed this as a major issue. Instead, the NAD report stated, "Management did not properly establish, enforce or set the proper example for procedure compliance." The failure to recognize the significance of the procedural compliance issue was considered a weakness. In response to this issue, procedural compliance training was given to many CPS employees. Additional training will be given at a later date.

The inspectors were concerned that the assessment focused entirely on the isolation of the RR loop. No assessment was made on several issues which arose during the event or contributed to difficulties encountered during the event. For example:

- There was little assessment of the problems encountered with LD-027. In addition, the appropriateness of the licensee's corrective actions for this item was not addressed.

- NAD failed to identify that the operators did not clearly understand what constituted total reactor coolant system leakage for possible entry into an Alert condition per the applicable Emergency Action Procedure.

- The assessment did not address the operators' decision to consider the plant to be in an "emergency" condition and then not to continue to pursue plant operations with this "mindset" once it was apparent that leakage could not be reduced to less than 5 gpm.

The NRC was concerned that since these areas were not addressed within the assessment there was the possibility that other areas may not have been thoroughly reviewed due to the narrow focus of the assessment.

The licensee's evaluation of the sequence of events from 2009 hours to 2030 hours stated that step 8.2.4.4 of CPS 3302.01 should have been a caution prior to step 8.2.4.6 which isolated the seal injection valve. The licensee felt that step

8.2.4.4 only described the conditions that must be met before closing the seal injection valve and did not direct that any actions be performed. The NRC disagrees with this assessment. Step 8.2.4.4 was a step in CPS 3302.01 on the day of the event. In addition, this step directed the control room operators to wait (which is an action) until RCS temperature was below 250°F prior to isolating seal injection. Furthermore, the procedural guidance to wait for the recirculation loop to cool down prior to isolating seal injection was directly supported by the vendor manual to prevent damage to the seal.

The NRC also disagreed with the licensee's initial assertion that the closing of the seal staging shutoff valve was in accordance with procedural requirements. As stated in Section O1.2, section 8.2.4 of the RR procedure contains an asterisk which symbolizes that the steps of the procedure must be performed in the order written. Since the step which closed the seal staging valve followed the step which directed that the reactor coolant temperature should be allowed to cool below 250°F, the seal staging valve should not have been closed before reaching the required plant conditions. The licensee subsequently revised its position.

Lastly, the NRC had several concerns with the licensee's long term corrective actions. Due dates for the completion of several long-term corrective actions at times appeared to be inappropriate. For example, the development of long-term actions to address several material condition deficiencies were not scheduled to occur until after RF-6. Therefore, while the immediate corrective actions performed may have resolved the material condition deficiencies prior to startup, it was unclear that the actions performed will prevent recurrence.

The licensee also planned to perform corrective actions to address the overall lack of planning and evaluation of potential consequences prior to performing infrequently performed evolutions. The inspectors were concerned that the schedule for completing these corrective actions would not support implementation prior to the beginning of RF-6, even though more infrequently performed evolutions are performed during refueling outages than during normal operations.

As identified in the NAD assessment of on-line maintenance, the lack of evaluating potential consequences prior to performing infrequently performed evolutions contributed to the automatic reactor scram on April 9, 1996. However, the licensee's corrective actions for the April 9 event were narrowly focussed and only addressed the items which were direct contributors. A broad based review to determine if other departments were considering potential consequences prior to performing infrequently performed evolutions was not performed. The inspectors consider this to be a weakness.

Due to the NRC concerns given above, the licensee issued a revised assessment report on September 20, 1996. This report was reviewed and determined to be more introspective and self-critical than the original assessment.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Request D60700, Reactor Recirculation Pump Seal Rebuild

a. Inspection Scope (62703)

The inspectors observed work performed under maintenance request D60700 and maintenance procedure CPS 8225.01, Reactor Recirculation Pump Seal Removal, Installation, and Maintenance, sections 8.1 and 8.7.

b. Observations and Findings

On September 6, the inspector observed maintenance workers in the assembly of a replacement RR pump seal cartridge. Each component and all replacement parts were inspected prior to installation. Supervision was at the job site or readily available when required. NAD provided almost continuous job coverage. The applicable procedure was at the job site with one working copy in the contaminated area and one copy just outside the area; the outside copy was updated (necessary sign offs, parts used, measuring and test equipment (M&TE) used, etc.) as work progressed. The maintenance workers performed their jobs in a professional manner and were familiar with the procedure. The work was completed without incident.

c. Conclusions

The referenced maintenance activity was completed thoroughly and in accordance with the procedures.

M1.2 Maintenance Request D60700, Reactor Recirculation Pump Seal Disassembly

a. Inspection Scope (62703)

The inspectors observed the disassembly of the failed RR pump seal. This activity was performed under maintenance request D60700 and maintenance procedure CPS 8225.01, Reactor Recirculation Pump Seal Removal, Installation, and Maintenance, section 8.5.

b. Observations and Findings

On September 10, the inspector observed the disassembly of the seal cartridge removed from the "B" RR Pump. The purpose of the disassembly was to gather data to determine the root cause of the failure.

The work was performed in a booth because of component contamination levels. Two maintenance personnel, a radiation protection technician, the system engineer and a representative from the NAD were within the booth to perform and observe

the iteration. The maintenance supervisor and another radiation protection technician (as well as the inspector) were stationed immediately outside the booth and observed the disassembly through windows. Both radiation protection technicians were constantly monitoring radiological conditions inside and outside of the booth. A working copy of the maintenance procedure used for this scope of work was located within the booth. All individuals were signed on to the proper radiation work permits.

Seal component conditions were as follows:

Overall Condition - The seal cartridge appears to have been properly assembled and installed following the last seal failure (December 1995). Wear on the seal faces was evident due to the noted scratching and "phonographing" indications found on the seal faces.

Upper Stationary Face - Eight wear marks were noted each originating in the outer cooling notch area. The marks varied in the number of wear channels formed (two were single channels, two were single channels with indications of the formation of secondary channels, one contained two wear channels, two channels did not completely traverse the sealing surface, and one channel which was approximately three times larger than the others and was "V" shaped with the open end being on the inboard side of the seal). The mean size of the channels appeared to be about 1/8 inch in width and depth with variances noted.

Upper Rotating Face - A crack or similar indication was noted on the seal face. Further analysis of the indication is required before speculating on the cause.

Lower Stationary Face - One wear mark through the raised face was noted. The indication originated at a cooling notch area and penetrated the seal face. The indication was larger than the general population of wear on the Upper Stationary Face and was "V" shaped vice the channels which were commonly found on the Upper Stationary Face; the indication was approximately 3/8 inch wide at its widest point.

Lower Rotating Face - Normal wear was indicated along with a crack completely through the seal ring. The crack appeared to be a recent failure in that no erosion was evident. The crack was a complete penetration. Further analysis will be required prior to determining a root cause.

Consumables - All o-rings and springs were in good condition. The o-rings remained pliable to the touch and none indicated signs of degradation or improper installation. The springs were consistent in size and shape with new springs.

Other Components - No indications were present which were beyond what would be expected for a seal which failed in this manner. There was some discoloration of the sleeves and other components which may be indicative of overheating; further analysis will be required prior to confirming the causes.

c. Conclusions

Maintenance activities associated with the seal package was completed thoroughly and professionally. Support by the system engineer ensured pertinent data was collected for later root cause evaluations. Radiation protection support was good to ensure the exposure of all involved was kept ALARA. Although none of the seal indications were unusual, further analysis of the failed components was continuing prior to determining the root cause of the failure.

III. Engineering

E1 Conduct of Engineering

E1.1 Reactor Recirculating Pump "B" Seal History Prior to the Seal Failure

a. Inspection Scope (37551)

The inspectors reviewed the "B" RR pump seal history, the licensee's procedures governing RR pump operation, the RR pump vendor manual (Sulzer Bingham, Manual No. K2801-0005, "RV Reactor Recirculation Pump"), and other licensing documents associated with pump and seal performance.

b. Observations and Findings

A review of historical records identified that the "B" RR pump had undergone seal replacement on at least eight occasions since plant startup; with one catastrophic failure occurring in June 1989. Although the exact root cause of these failures has not been determined, most instances of seal degradation occurred soon after a plant transient or plant restart; consistent with the information provided in the vendor manual.

On April 9, 1996, the unit experienced a partial loss of off site power that resulted in the trip of the operating CRD pump and the loss of seal injection to both RR pump seals. (The unit also experienced a reactor trip.) During this event, the RR pump seals were subjected to reactor coolant temperatures and pressures for a period in excess of 1.5 hours. As a result, temperatures in the "A" RR pump seal cavities reached approximately 290°F. The vendor, Sulzer Bingham, recommended rebuilding the "A" RR pump seal due to possible O-ring and seal degradation as a result of the pump being exposed to elevated seal cavity temperatures.

In their engineering assessment of system and component performance during this trip, the licensee determined the "A" RR pump to be operable; the "A" RR pump was returned to service without the seal package being replaced. Although not stated in the assessment, engineering considered the "A" pump operability assessment to have enveloped any concerns with operability of the "B" pump.

In reviewing the licensee's assessment, the inspectors reviewed the licensee's response to Item II.K.3.25. of NUREG-0737, entitled "Effect of Loss of Alternating Current Power on Pump Seals." This action item required the licensee to determine the ability of the reactor recirculation pump seals to withstand a complete loss of pump seal cooling for a period of 2 hours. In response, the licensee sponsored a study through the Boiling Water Reactors Owners' Group to review this issue. Although the results of this study indicated that the loss of pump seal cooling for 2 hours was not a safety problem; the study stated, "seal repairs may be required prior to resuming operation."

As the basis for dispositioning the operability of the "A" RR pump, the licensee cited the results of a singular study conducted by Sulzer Bingham which demonstrated that the Ethylene Propylene Rubber (EPR) O-rings could withstand temperatures of approximately 600°F without being degraded. Based on this and the fact that the "A" RR pump seal pressures and temperatures were normal when the unit was returned to service, no further action was recommended. This decisions was contrary to the recommendation of the vendor. (Note: The inspectors, during their review, could not determine if the Sulzer Bingham study addressed the condition of the seals at elevated temperatures; it appeared that the study did not address this particular issue.)

During a follow-on discussion with engineering, the inspectors discussed their concerns with the apparent weaknesses of this assessment. The inspectors concern was based on the apparent narrowness of the assessment. During this conversation, the Director - Plant Engineering stated that the thoroughness of the operability assessment was proven when the "A" RR pump performed satisfactorily upon being returned to service. The inspectors questioned the Director - Plant Engineering on this and discussed that equipment performance was not an appropriate basis from which to defend the thoroughness of an operability assessment; the purpose of an operability assessment is to determine, through engineering analysis, whether or not a component should be considered operable before it is returned to service or called upon in an accident scenario. The inspectors considered this statement by the Director - Plant Engineering to be poorly thought through before being offered as a response to the inspectors' concerns with the weaknesses identified in the "A" RR pump operability assessment.

The inspectors also identified several apparent discrepancies between the licensee's RR pump operating procedures and guidance provided in the RR pump vendor manual. The discrepancies involved RR pump seal problem response action as detailed in Table 1, "RR Pump Seal Key Parameters," of CPS No. 3302.01 and procedural guidance for isolating CRD seal injection flow. The identified differences included:

- The recommendation, as identified in the vendor manual, to immediately shut down the RR pump on low or high P_2 pressure. (Note: low P_2 pressure indicates high upper seal leakage and high P_2 pressure indicates high lower seal leakage.) The licensee's procedures does not identify this condition as

requiring an immediate shutdown of the RR pump; instead, this condition only requires an evaluation to support continued operation of the pump.

- The recommendation, as identified in the vendor manual, to immediately shut down the RR pump if the seal leakage exceeds 1.0 gpm. The licensee's procedure does not identify this as a required shut down condition; instead, operators are directed to shutdown the pump only if the TS action statement limits of TS 3.4.5, "RCS Operational LEAKAGE," are exceeded.

- The recommendation, as identified in the vendor manual, to maintain injection and cooling flows as long as the primary system is above 150°F. The licensee's procedure states that prior to isolating CRD seal injection flow, allow the idle loop to cooldown to < 250°F unless the RR pump seals are failed.

Additionally, the inspectors noted the vendor manual stated that, "The seal staging valve must be open (Note: This valve is only closed during loss of injection on an idle pump.") Although the licensee's procedure is written to ensure the staging valve remains open until seal injection is secured, the staging valve was closed during this event prior to securing seal injection.

The inspectors reviewed the available correspondence between the licensee and the vendor to determine if any of these discrepancies were addressed and resolved; no documentation between the licensee and the vendor could be found to support the relaxation of the vendor's recommended operating guidance for the RR pump. However, the inspectors did review documentation between the licensee and General Electric which provided justification for exceeding the values given for various seal parameters in the vendor manual. This correspondence addressed several concerns raised by the NRC on RR pump seal instrumentation and operating parameters in June of 1989. In response to a question concerning Clinton's position on recommended shutdown parameters contained within the vendor manual the following was provided:

> "Vendor manual recommendations are meant to protect the particular equipment from further degradation. The decision as to how this recommendation fits into the overall plant operating scheme involves more complicated considerations of other plant demands and operating conditions and are the prerogative of the Plant Operators. CPS design does not require immediate pump shutdown if the seal parameters exceed the limits given by the pump vendor as recommendations."

This issue is an Inspection Follow-up Item (IFI 50-461-96010-02).

While the generic issue pertaining to licensees following vendor recommendations remains an open question, Clinton's evaluation of the "B" seal package is indicative of a non-conservative approach to plant materiel condition. In April 1996, the plant experienced a significant plant scram with both recirculation pumps' seal injection system being lost. While the "A" seal performed well after the restart, the "B" seal

began to exhibit seal degradation shortly after restart. In June, 1996 the plant experienced another reactor scram thereby providing an opportunity for replacement of the damaged seal. It does not appear that engineering assessed the current seal condition taking into account the seven previous seal failures, the transient conditions experienced in April, subsequent indications of seal degradation, in conjunction with the vendor recommendations.

c. Conclusions

The failure to consider all available generic data, particularly licensing information and vendor recommendations, in assessing the operability of the RR pump, demonstrated a lack of rigor in the assessment process. Additionally, the performance of system engineering during the period leading up to the failure of the "B" RR pump seals was weak; demonstrating a non-conservative attitude in the assessment of plant material condition.

E1.2 Preliminary Investigation of Reactor Recirculation Pump Seal Failure

a. Inspection Scope (37551)

The licensee's inspection of the components which comprised the "B" RR pump seal cartridge involved in-depth analysis of each component with the assistance of the component supplier (Bingham-Williamette) and an independent pump engineering company (Atomic Energy of Canada Limited, or AECL). Plant parameters recorded during the seal failure event were also integrated into the root cause analysis. The final analysis was preliminary in nature pending the incorporation of data obtained from the destructive testing of some or all of the components (to be completed at a later date).

b. Observations and Findings

The failure of the seal cartridge was preliminarily attributed to water clarity/dirt issues in the cartridge. Preliminary data supports the concept of a slow seal failure (commencing in April of this year) culminating in the seal seating surfaces being hydraulically held open by primary coolant flashing to steam following the securing of control rod drive seal injection flow. Plant parameters (seal pressures and temperature, drywell leakage, etc.) support this concept.

One anomaly existed which the data doesn't support at this time. That anomaly was a crack indication across the upper rotating ring. There were differing views between the parties involved as to the cause of the indication but all involved engineers concluded that, pending the receipt of more data, the indication was not a part of the overall problem leading to seal failure. Further studies of this anomaly were anticipated prior to closing the issue.

The inspector noted that there were no formal procedures for performing this type of inspection. The parties involved initiated the process by developing a formal flowpath to follow prior to drawing any conclusions. The pertinent data was

displayed and the seal components were examined. The vendors were segregated so that independent conclusions could be drawn. Other teams developed time dependent graphs of plant parameters to depict essential parameter changes in a logical and concise way. The need for a formal procedure in this case was minimal due to the way the data was promulgated and the way the results were obtained.

c. Conclusions

The site engineers and the vendor representatives concluded that the seal failed due to water clarity and dirt problems. Except for the indication described above (which requires further investigation) and the finding of a crack in the lower rotating seal face (attributed to heat generated stresses following the securing of injection flow), all data supported that conclusion. Heat checking indications on some seal components also warranted further investigation. Additional investigations were planned to further quantify the failure mode and to aid in the development of corrective actions.

The fact that the seal faces may be hydraulically forced open during this type of event may be a new phenomenon. Usually, leakage through the seal will decrease as the RR pump is secured and the recirculation loop is isolated. Preliminary analysis shows that this scenario may take place when attempting to isolate a recirculation loop with badly degraded seals but more investigation is required.

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Safety Relief Valve (SRV) Anomalies

a. Inspection Scope (37551)

During a review of data pertaining to the recent plant shutdown and associated events, the inspector noted that four of the six SRVs known to be leaking past their seats (prior to the event) exhibited increased leakage although reactor pressure was decreasing or holding at lower than full power operations. It was anticipated that the leakage amount would decrease with the decrease in reactor pressure.

b. Observations and Findings

The inspector interviewed the system engineer in an attempt to determine why the anomaly occurred. Initial thoughts were that the tail pipe thermocouples were surface mounted on the tail pipe and that the four tail pipes were mounted in the same general area such that a change in local ambient conditions would cause the main control room instruments/printers to indicate higher than actual. This was found to not be the case since the tail pipes were insulated and not all of the tailpipes were in the same general area.

The system engineer then researched similar plant conditions (shutdown in progress) and compared that data to the SRV tail pipe temperatures previously recorded. The review determined that the same traits were exhibited during past

events. The conclusion was drawn that thermal stresses in the SRV change as reactor conditions change. In addition, the increased leakage anomaly was consistent with previous plant shutdowns. Specifically, the gaps between the SRV disc seat and body (existing leak) may increase in size as conditions change (due to the masses of these components being different causing them to expand/contract at different rates) thus increasing leakage and tail pipe temperatures with the reduction of reactor power and pressure.

c. Conclusions

The licensee failed to recognize this condition until brought to their attention by the inspectors. Once site engineers began investigating the occurrence, they were thorough in eliminating obvious explanations as well as in resurrecting old data in an attempt to understand what was causing this occurrence. The data does support the argument that SRVs which are leaking slightly under full power conditions will probably leak more during a controlled shutdown and that they will return to the pre-transient leakage rates (tail pipe temperatures) upon reaching full power conditions.

E2.2 Updated Safety Analysis Report Review

As part of this inspection, the inspectors reviewed the applicable portions of the Updated Safety Analysis Report. No discrepancies were noted.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 4, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X3 Management Meeting Summary

On September 13, Mr. Bill Beach, Regional Administrator, and Mr. Melvyn Leach, Chief-Operator Licensing visited Clinton Power Station. A management meeting was held at Clinton Power Station to discuss the licensee's review of the seal failure event.

On September 23, a management meeting between Illinois Power and the NRC was held in the Region III office. The purpose of the meeting was to discuss the licensee's assessment and planned actions in response to the reactor recirculation seal event and the subsequent reactor shutdown.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

PERSONS CONTACTED

Licensee

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D. Morris, Director - Radiation Protection
A. Mueller, Director - Assistant Plant/Manager - Maintenance
M. Lyon, Director - Assistant Plant/Manager - Operations
D. Antonelli, Director - Plant Support Services
C. Elsasser, Director - Planning & Scheduling
M. Stickney, Supervisor - Regulatory Interface

LIST OF ACRONYMS

ALARA	As Low As Reasonably Achievable
CPS	Clinton Power Station
CRD	Control Rod Drive
DRP	Division of Reactor Projects
EAL	Emergency Action Level
EAP	Emergency Action Procedure
EEI	Escalated Enforcement Item
EO	Equipment Operator
EOP	Emergency Operating Procedure
FW	Feedwater System
GPM	Gallons per Minute
IFI	Inspector Follow-up Item
IP	Illinois Power
IR	Inspection Report
LASS	Line Assistant Shift Supervisor
LCO	Limiting Condition for Operation
LD-027	Unidentified Drywell Leakage Monitor based on sump run times and measured pump flow rates
MDFP	Motor Driven Feed Pump
M&TE	Maintenance and Test Equipment
NAD	Nuclear Assessment Department
PDR	Public Document Room
PMSO	Plant Manager's Standing Order
RCS	Reactor Coolant System
RF-6	Refueling Outage - 6
RFP	Reactor Feed Pump
RG	Regulatory Guide
RO	Reactor Operator
RR	Reactor Recirculation
RT	Reactor Water Cleanup System
SRV	Safety Relief Valve
STA	Shift Technical Advisor
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
V-Notch	Real Time Leakage Detection System In Drywell (Both identified and unidentified leakage have the system)

CHRONOLOGY OF CLINTON SEAL FAILURE

TIME	ISSUE
9/5/96	
0600	Morning Initial Conditions: RR Suction Valve 23B stem temperature 149°F (indicative of steam leakage) DW cooler drain flow ~.5 gpm Trend visible on FPM fission product monitor for containment (~3400 cps Alarm Locked In) RR "B" pump seal pressures: inner 1020 psig outer 484 psig DW floor leakage (FL) 3.85 gpm (via LD-027)
1430	Mechanical maintenance begins flush of cycled condensate header in containment in preparation for RR seal replacement. Flush is directed to suppression pool with a flow of approximately 50,000 gallons per day.
1645	DWFL 3.87 gpm
1712	DWFL 3.96 gpm
1800	Single loop operations brief completed. Items discussed included actions to take if seal leakage increased, actions for reactor scram, and actions for feedwater pump problems.
1805	Commenced reducing power with rods per nuclear engineering instructions. Initial Reactor power was 100%, with a power decrease of 100 Mwe/hr.
1944	Completed reduction of power to 81% by use of control rods.
1950	Increased recirculation flow in Loop A to prevent too much drop in power as Loop B flow is reduced. Minimal power increase.
2001	Began closing Loop B flow control valve in accordance with CPS 3302.01 "Reactor Recirculation." Several pauses were made as feed water heater alarms came in due to changing feed rates. Reactor power 80%.
2009	**Shutdown the B RR pump** Final Reactor power 58%. inner and outer RR pump "B" seal pressures began equalizing.

Seal cavity temperatures start to increase from about 120°F

2010~	**Loop B discharge valve (1B33F067B) closed.** Electricians verified by signature trace.
2015~	**F106 RR Loop B suction for RT closed.**
2025~	Reactor operator calculates it will take greater than 6 hours to cool the idle RR loop to 250°F. Second reactor operator confirms calculation. Calculation was verified by assistant director of operations.
2027	Control & instrumentation technician aligning average power range monitoring system for single loop.
2030	**Shut 1B33F075B (RR seal staging flow)** Attempted to increase the RR loop cooldown by directing this portion of seal injection water into the loop. *This action was performed out of sequence from the procedure. It was to be performed only in the event of an emergency condition (such as a significant system/seal leak).* <u>Note:</u> This was before the leakage rate increased. DWFL 4.22 gpm RR loop "B" suction temperature 511°F
~ ~ ~	RR suction valve 23B packing temperature 207°F
2055	**Exceeded TS 3.4.5 limit for unidentified leakage $\geq$ 5.0 gpm.** **Began 4 hour action statement to reduce leakage** (CPS 4001.01 Reactor Coolant Leakage). DWFL 5.52 gpm
2100	Inner and outer RR pump "B" seal cavity temperatures stabilize at about 145°F. This trend information only. Temperatures do not represent actual pump seal temperature.
2110	Declared **UNUSUAL EVENT**
2112	Entered CPS 4008.01, Abnormal Reactor Coolant Flow. Assessed condition and exited CPS 4008.01
2118~	DWFL 5.86 gpm
2122	Suppression pool level 19 feet 4 inches, temperature 86°F

2127 Placed RHR B in suppression pool cooling to provide a letdown path for lowering suppression pool level.

2130 Closed RR suction valve 23B in accordance with "emergency" isolation section of the procedure.

Completed isolation of RR pump B per section 8.2.4 with the exception of 1C11-F026B, the seal injection isolation valve.

Both inner and outer RR pump "B" seal pressures at 980 psi.

2144 **Entered TS 3.4.5 for unidentified leakage increasing ≥ 2 gpm in a 24 hour period.**

NRC notification complete for Unusual Event

DWFL 5.94 gpm

2159 **Shut 1C11-F026B CRD seal injection path.**

This completed loop isolation. This decision was made after determining that the loop was not going to depressurize through the seal with CRD flow lined up. This decision further jeopardized the seal package.

This step was performed contrary to procedure. The procedure stated that prior to isolating CRD injection flow, one of two conditions had to be met. Either the loop was to be cooled down to less than 250°F, or, the RR seals had already failed, (which was defined as the loop depressurized to approximately drywell pressure.)

2159 Strip chart recorders show that seal cavity temperatures start to rise.

2200~ DWFL 6.13 gpm

2200 RR pump seal temperature 138°F (trend info only)

2208 Plant manager arrives due to Unusual Event.

2213 RR pump seal temperature 151°F (trend info only)

2215 Strip chart recorder shows that seal cavity temperatures increase to greater than 150°F (trend info only).

Also, seal water discharge temperature starts a dramatic increase from about 110°F to over 215°F in a few minutes. (data from strip chart)

2218~ Received RR B seal cavity high temperature alarm.

2220~ Reactor operator informed resident (required by procedure) that seal temperature had reached 160°F.

2222 **Sudden failure of RR B seal**. Seal pressure decreased rapidly from 950 to 280 psi within a few seconds.

Containment was evacuated per CPS 4001.01.

Drywell pressure started to increase from a value of .26 psi and the B mixing compressor was started.

Note: As leakage exceeded 7.99 the LD-027 instrument locked at 7.99 and did not go higher. Operators were not aware of this. The operating procedure for leak detection and the off normal procedure for abnormal reactor coolant leakage did not address this fact.

Remaining leakage data will be from STA calculations

DWFL 5.6 (reconstructed after 2255 hrs)

2226 Stopped drywell mixing compressor at a pressure of .40 psi. Peak drywell pressure was .45 psi. Drywell pressure dropped to .12 psi as steam condensed in the drywell. No vacuum breakers opened.

2227 Shutdown RHR B from suppression pool cooling and placed into standby condition. (Stopped lowering suppression pool level.)

2230 DWFL 24.0 gpm (reconstructed, NRC calc 19.9).

The licensee calculation for DWFL did not take credit for the time period that the sump pump was running. This resulted in lower leak rate calculations.

2237 DWFL 38.1 gpm (reconstructed, NRC calc 31.1)

2246 DWFL 20.8 gpm (reconstructed, NRC calc 17.6)

2255~ Oncoming STA entered the Control Room (2248 hours) and discovered that the floor drain flow rate indication (LD-027) was inoperable. Entered actions for leak detection instrumentation per technical specifications. On-shift STA began performing manual leakage calculations.

2257 DWFL 15.7 gpm (NRC calc 13.7)

2309 DWFL 12.5 gprn

2322 DWFL 14.1 gpm

2337 DWFL 16.5 gpm (NRC calc 14.8)

2351 DWFL 11.6 gpm

9/6/96
0006 DWFL 10.8 gpm

0020 DWFL 13.2 gpm

0035 DWFL 13.1 gpm

0039 Suspected leakage to RR loop B through RT valve G33-F106. Isolated RT by shutting 1G33-F100 & F102

0050 DWFL 10.3 gpm

0055 **Exceeded 4 hour LCO for unidentified leakage.**

Entered 12 hour reactor shutdown statement. Control room operators directed to review procedures for normal reactor shutdown.

0104 DWFL 10.1 gpm

0118 DWFL 10.6 gpm

0200 Control room briefing held to reduce reactor power.

0230 Power decrease commenced.

0612 Report of fire in service building.

0615 Six operators on scene. No fire exists.

0623 **Suppression pool level reaches 19 feet 5 inches. High suppression pool level alarm annunciated, TS LCO 3.6.22 and Emergency Operating Procedure 4402.01 were entered.** The licensee's assessment stated the SP water level increase was due to leaking SRVs (approximately 5000 gallons per day). However, maintenance personnel had been flushing water from a cycled condensate header to the suppression pool at approximately 50,000 gallons per day which was the major contributor.

0644 RHR "B" placed in suppression pool cooling to allow a portion of the suppression pool water to be rejected to radioactive waste processing.

0700 Reactor power 23%

0717 RHR "B" secured from suppression pool cooling.

0945 Personnel error - reactor operator returns switch past the neutral position causing momentary denergization of 6900v 1B bus. This action distracted

operators from normal shutdown activities as they must first recover the equipment that was tripped due to the error.

1106 Turbine off of the grid.

1206 Manual reactor scram as part of normal shutdown, enter mode 3.

Enter 36 hour statement to reach Mode 4

1543 DWFL 5.5 gpm

1645 DWFL 2.2 gpm

1750 DWFL 2.1 gpm

2150 Exited Unusual Event for excessive unidentified leakage.

2316 Entered Mode 4.

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	50-461/96011(DRS)
Licensee:	Illinois Power Company
Facility:	Clinton Power Station
Location:	Route 54 West Clinton, IL 61727
Dates:	September 5 through October 4, 1996
Inspectors:	M. Leach, Chief, Operator Licensing Branch T. Kobetz, Senior Resident Inspector, Pt. Beach D. Desaulniers, Human Factors Specialist D. Hills, Lead Engineer N. Hilton, Resident Inspector, Byron C. O'Keefe, Resident Inspector, Fermi J. Lara, Resident Inspector, Monticello E. Plettner, Examiner
Approved by:	M. Leach, Chief, Operator Licensing Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Clinton Power Station
NRC Inspection Report 50-461/96-011

This inspection report includes the results of an operational safety team inspection conducted from September 16, 1996, to October 4, 1996. This inspection was a broad evaluation of the conduct of routine operations and maintenance and engineering support to operations.

Operations

- The operations department did not have safety as its highest priority. Operators did not feel they were in charge of the plant. They also felt support to the operators from other departments was weak (O1.3).

- The conduct of operations lacked rigor and there was also a lack of formality in the control room (O1.1 & O1.2).

- Short term relief turnovers in the control room were occasionally weak or nonexistent and necessary information was not relayed (O1.2).

- Variations existed from shift to shift in crew communications and annunciator response. This indicated a lack of management oversight (O1.1).

- Operator logs and rounds sheets were weak (O1.1).

- Adherence to procedures was weak. Examples included operators failing to isolate the idle train of spent fuel pool cooling and an operator failing to complete the loop seal fill of the control room ventilation system (O3.3).

- A significant procedure change backlog existed with some items dating back to 1992 (O3.4).

- The operations department monthly review of overtime was not being performed (O1.4).

- The operations department missed identifying problems due to a high threshold (O8.1).

Maintenance and Surveillance

- The operators were not aggressively identifying problems and were living with a number of long-standing material condition problems which could have complicated the operators' response to plant transients (M2).

- Surveillance procedures were weak. Two examples of emergency diesel generator preconditioning were identified and the procedure for the local leak rate test of some main steam system valves was inadequate in that it failed to provide the necessary steps to bypass and then restore a group I containment isolation signal (M3).

Engineering

- System engineer direction to operators was weak in that tests were conducted by direction of the system engineer using action plans or implementation plans. These activities should have been performed using approved procedures (E3.2).

- The operability evaluation program was poor. The process for performing operability evaluations was poorly described, examples of poorly documented evaluations were identified, and no controls were in place to disseminate information to operations personnel and track recommendations (E3.3). Two operability evaluations with inadequate corrective actions were identified including the automatic start of the control room ventilation chiller (E3.5) and 46 oversize motor operated valve actuators (E3.4).

- Safety reviews were weak with inadequate or missing reviews for disabled annunciators, an inadequate review of a spent fuel pool cooling procedure change, an inadequate review of a degraded cathodic protection system, and no review for a seismic concern for annunciator response procedure binders stored above control room operating panels (E3.1).

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Report Details

Summary of Plant Status

The unit remained in cold shutdown for the entire period of the inspection. Major work activities were planned surveillances prior to a projected unit start up.

I. Operations

O1 Conduct of Operations[1]

O1.1 Crew Operating Practices

a. Inspection Scope (93802)

The inspectors performed sustained control room and in-plant observations to assess the performance of the supervisors and the licensed and non-licensed operators. The inspection activities included review of the following procedures:

- Clinton Power Station (CPS) 1014.01, "Safety Tagging," Rev. 21
- CPS 1401.01, "Conduct of Operations," Rev. 24
- CPS 9065.02, "Secondary Containment Integrity," Rev. 26
- Plant Manager Standing Order (PMSO) PMSO-050, "Execution of Technical Specification or ODCM Requirements", Rev. 3

b. Observations and Findings

CPS 1401.01 states verbal communications which either direct the operation of or report the status of equipment shall require a verbal repeat back. This repeat back should be acknowledged by the initiator. This communication method is generally termed three-way communications.

The inspectors noted that control room decorum was crew dependent. Some operating crews were very professional; only work related conversation was noted and control of personnel into the "controls" area was good. Other crews were more informal; non-operations personnel entered the "controls" area without requesting permission of the operating crew. Information concerning the status of plant equipment was generally shared among the operating crew members. However, on September 18 the Line Assistant Shift Supervisor (LASS, the senior reactor operator in the control room) received a phone call informing him that a single phase cable had been inadvertently severed during a trenching operation in the protected area. At the time of the call the identity of the cable was unknown.

[1] Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

The LASS failed to brief the crew concerning this event to heighten their sensitivity to any unexpected indications or equipment responses. The inspectors also noted the LASS on some crews would become involved in work activities, such as acknowledging annunciator alarms, rather than maintaining a supervisory role. This characteristic was also observed during the September 5, 1996, event.

The inspectors observed control room operators were usually notified of expected annunciator alarms; however some exceptions to this are discussed in section O1.2 of this report. Operator response to annunciator alarms was mixed. The inspectors observed the operators correctly respond to numerous alarms in both the main control room (e.g., low flow steam jet air ejector condenser), radwaste operations control room (e.g., radwaste filter high differential pressure), and locally in the plant (e.g., high differential pressure in the fuel building). In each case, the response was immediate, annunciator procedures were appropriately referenced, and the alarm was communicated to other operators and appropriate corrective action taken. However, the inspectors also observed a few instances of weak annunciator acknowledgement. Also, verbal repeat backs were not always used during the communication of annunciators. The quality of the communication varied according to crew observed. Some announcements were clear and distinct, including repeat backs, while others were simply verbal announcements without ensuring the attention of other crew members.

On September 21, the inspectors observed the licensee performing portions of CPS 9065.02. However, the LASS had to suspend the test during step 8.5, which requires the outside barometric pressure to be obtained from barometric pressure instrument EM-BA201. The LASS had failed to identify before starting the test that the power supply for EM-BA201 was out-of-service for maintenance.

Operators appeared to be generally knowledgeable of plant equipment. An exception was the function of indicating lights on numerous temperature control devices on ventilation panels throughout the plant. None of the rounds operators questioned were aware of the indicating light functions. The licensee later determined that the exact function was equipment dependent, providing indication of such parameters as power available and operating status of controlled equipment. Operators apparently were not utilizing these indications.

The inspectors observed shift management tell the crew that they should do things right "since we do have people watching." This was a direct reference to the inspectors. The inspectors also received numerous comments from operators that they were glad the inspection team was here so that some problems could be fixed.

The inspectors observed two of two crews in the simulator perform non-conservative actions with respect to reactivity control. With the simulator reactor not quite critical, the operators diverted steam to heat up a steam line while continuing to withdraw control rods. This action applied two positive reactivities at the same time which was non-conservative. The licensee's reactivity management guidelines will be reviewed during a future inspection (50-461/96011-01).

The inspectors reviewed the control room logs and determined log entries documenting entry into Limiting Conditions of Operation (LCOs) and Operational Requirements Manual (ORM) requirements lasting less than a shift were incomplete in a number of cases in that inspectors were unable to determine what system was involved, which Technical Specifications (TSs) were entered, or what actions were required or taken. In a few cases, the complete log entry was: "Entered (or exited) Short Term Operational Requirements Manual (Short Term ORM or STORM)." As a result of not referencing a specific LCO, site personnel would be unable to verify that proper actions were taken. Although not contrary to procedures, unexpected alarms were not always documented in operator logs. Administrative procedures, in general, set a fairly high threshold for logging requirements.

The inspectors reviewed the process for controlling LCOs. The LCO records included a number of optional sheets, which if used, did identify all appropriate information. However, no clear mechanism appeared to exist for updating LCO status when conditions changed. For example, High Pressure Core Spray (HPCS) was inoperable for maintenance on July 1-7, 1996, which necessitated entry into a 14 day LCO. However, twice during this period, low pressure coolant injection loop "B" was made inoperable to place the system in suppression pool cooling due to Safety Relief Valve (SRV) leakage heating up the suppression pool. With these two emergency core cooling systems simultaneously inoperable, the plant was then in a 72 hour action statement. The two LCO sheets were not linked administratively, nor did the HPCS LCO reflect the change of action statement for either period when low pressure coolant injection was made inoperable. Control room log entries likewise did not reflect the change in LCO status for HPCS. It was not clear to the inspectors that the operators had recognized the change in LCO. On occasions the licensee entered and exited short term LCOs several times to perform surveillances immediately prior to an outage for the system. The licensee would then enter the LCO a final time for the system outage. Examples of this practice included a reactor core isolation cooling outage begun on July 9, 1996 and a HPCS outage begun on July 1, 1996. This method of repeatedly entering LCOs was non-conservative in that this practice could allow increased time for the outage, although in these specific examples the work was completed well within the LCO allowed times. The inspectors concluded the licensee's log keeping practices were weak.

The inspectors determined many control room and plant operator rounds sheets had few places to record plant parameters. The inspectors noted that the surveillance documents did not require a value to be recorded for each parameter or indication. The allowed band was printed with the indication and the operator was required to initial the log, indicating that the actual value was within the band. Additionally, the operator did not maintain a formal series of log readings from control room indications. An informal sheet had been developed by the operators to track significant parameters but was not part of a procedure. Most equipment entries were simply marked by a checkmark in the log. This method precluded daily or shiftly trending of parameters. The inspectors considered the lack of available operating parameter information, including trends, a weakness.

The inspectors observed the performance of shiftly channel checks of the analog trip modules in the control room. Again, no values were recorded during the performance of this TS-required surveillance, and acceptance criteria for the comparison between channels did not exist. The inspectors quizzed licensed operators on the same shift, and all agreed that values should agree within about 10 percent. However, PMSO-050, Section 6.0 stated that "channel checks are qualitative...A 10 percent deviation may be acceptable on one instrument and grossly unacceptable on another." The operators questioned were unaware of the correct content of this guidance document. The inspectors concluded that some operators performing this TS-required surveillance could have unknowingly accepted unacceptable divergence between trip channels. Because values were not recorded and acceptance criteria were not specified, supervisory reviews of the logs would not identify the error or detect an instrument problem which was missed by the operator performing the surveillance.

The inspectors identified electrical equipment labelling deficiencies. Direct current distribution panels in motor control centers 1D, 1E and 1F , which provide power to safety-related loads, had no load description labels. One Shift Supervisor (SS) stated to the inspectors that the problem also existed in lighting panels and 120 volt panels.

O1.2 Operator Turnovers

a. Inspection Scope (93802)

The inspectors attended operations shift turnovers during the period of continuous control room coverage in order to determine the effectiveness of shift turnovers. Control room documentation (e.g. logs, turnover checklists, night orders) were reviewed to determine availability and usefulness. The inspectors attended turnovers after observing operations for a shift to verify the effectiveness of the turnover of items that developed during the observed shift.

- CPS 1001.05, "Authorities and Responsibilities of Reactor Operators for Safe Operation and Shutdown," Rev. 8
- CPS 1401.01, "Conduct of Operations," Rev. 24

b. Observations and Findings

The inspectors observed formal control room turnovers were generally adequate to convey pertinent information: control room operators walked down panels in company with their counterparts and discussed equipment status, and checklists were properly utilized to assist in the turnover of important information. A brief for the entire oncoming crew was conducted outside the area of the control room, thereby not distracting the control room operators, prior to assuming the watch. However, during face to face turnovers, control room traffic and business were not limited to minimize turnover time and maximize effectiveness. As a result, turnovers were observed to last for an excessive period of time. The inspectors also observed the operators on occasion did not challenge other operators on the

status of equipment. For example, on September 18, at the turnover for swing shift, the oncoming "B" Reactor Operator (RO) asked about the reason a piece of equipment was out of service. The offgoing RO could not remember the reason, and that answer was accepted without further inquiry or consulting other operators nearby.

The inspectors observed interim turnovers for temporary relief on occasions were extremely short (i.e. only a few seconds), a formal statement of relief was not always made to the LASS or other watchstanders, and necessary information was not conveyed. The following specific weaknesses were noted during interim turnovers:

- On September 18, the "A" RO, designated to be the "at the controls RO," left the area designated by CPS 1001.05, as the "at the controls" portion of the control room for approximately 3 minutes without the knowledge of other control room operators and without conducting any turnover.

  10 CFR 50.54(m)2iii states when a nuclear power unit is in an Operational mode other than cold shutdown or refueling, as defined by the unit's Technical Specifications, such licensee shall have a person holding a Senior Reactor Operator (SRO) license for the nuclear power unit in the control room at all times. In addition to this SRO, for each fueled nuclear power unit, a licensed RO or SRO shall be present "at the controls" at all times. Contrary to the above, the "at the controls RO" left the at the designated controls area without a proper relief. This was an apparent violation of 10 CFR 50.54(m)2iii (EEI 50-461/96011-02).

  Additionally, the inspectors were concerned that when the LASS identified that the "A" RO was missing, he did not counsel the individual nor promptly inform the SS, nor was a Condition Report (CR) written by the operations department (see Section O8.1). When the inspectors identified the issue to the SS, he stated he would discuss the matter the next day with the shift.

- On September 17, the LASS was informed by phone of activities that would affect fuel building differential pressure. The LASS failed to inform the operating crew or the SS providing short-term relief for the LASS before leaving the control room. Shortly after the LASS left the control room, the "High Differential Pressure Fuel Building" annunciator alarmed in the control room. An operator was dispatched to investigate the cause of the alarm. Within minutes the LASS returned, and upon learning of the alarm informed the crew the alarm was expected.

  CPS 1401.01, Section 8.4.3.13 states that the RO "At The Controls" and the LASS may be relieved for short periods of time for personal reasons. As a minimum, the person being relieved shall inform the relief of the current plant status, operations in progress and work to be performed in the immediate future. Failure to perform an adequate turnover of current plant status was an apparent violation of TS 5.4.1 (EEI 50-461/96011-03a).

- The inspectors observed one RO about to leave the control room without providing a turnover to his relief. However, the SS on this occasion stopped the operator and corrected the situation.

O1.3 Support of Operations

a. Inspection Scope (93802)

The inspectors reviewed operating practices and operator control of activities at the station. The inspectors conducted interviews, and discussed with operators their perception of operator control over station activities. The inspectors also reviewed the following procedures and standing orders to evaluate the direction provided to operators:

- CPS 1001.05, "Authorities and Responsibilities of Reactor Operators for Safe Operation and Shutdown", Rev. 8
- CPS 1401.01, "Conduct of Operations", Rev. 24
- Operations Standing Order (OSO) OSO - 090, "Expectations for Operating Crew Members", Rev. 4.

b. Observations and Findings

On September 19, the inspectors observed control room operators attempting to identify a source of water draining into the control building sump (see Section O8.2). During the shift, the Nuclear Equipment Operators (NEOs) searched for the source of the water, the shift technical advisor (STA) prepared a list of all possible inputs, and the control room operators checked with maintenance groups for possible changes from the previous day. At the suggestion of an RO, the LASS requested a chemistry sample to help determine the source. The inspectors observed the LASS explaining all of the actions the operators had taken. The inspectors questioned the LASS after the phone call and he explained he had to justify his request to the chemistry supervisor. The LASS reported that providing justification for a request was common.

CPS 1401.01 section 8.3.2, "Conduct of Personnel - Routine," discusses SS responsibilities for ensuring personnel adhere to the rules for good conduct. Ten items are listed in this section which includes, for example, maintain good housekeeping practices as item "e." The two items involving reactor safety appear low in the list as items "h" and "j." CPS 1001.05 provides guidance primarily relevant to emergency operating procedures (EOPs). For example, the SS responsibilities listed were principally related to identification and implementation of emergency procedures. The inspectors concluded both CPS 1401.01 and 1001.05 appeared adequate; however, neither prioritizes safe and conservative operations as the primary responsibility of the licensed operators.

OSO - 090 focused on customer satisfaction. The definitions section discussed customers and noted that the operations department provided services to organizations both on and off site. Examples included providing maintenance

support for scheduled maintenance and coordinating power changes with Electric Dispatch to maximize system stability and availability. The specified attributes included a safety focus for the SS and the RO at the controls; however, most operators were tasked with a goal of 100 percent customer satisfaction and the LASS "tracks the status of assigned jobs and communicates progress to the SS on a regular basis, keeps the SS involved in decisions to not allow performance of a scheduled maintenance activity, and strives to provide 100% satisfaction to our customers." Safe, conservative operations was not mentioned in the LASS attributes. The inspectors concluded that OSO - 090 focused on schedules and unit production rather than safe, conservative operation. During a presentation by licensee management on safe operations, the inspectors observed one reactor operator comment that he previously had feared that he would have lost his job if he had taken action to shut down the unit.

Several operators stated that the operations department was not controlling activities, most indicated that accomplishing the scheduled activities was the most important criteria of success. Some operators were frustrated with their inability to get some equipment fixed. Operators repeatedly expressed the opinion that operations had very little input on the maintenance schedule. During the inspection, operators repeatedly showed the inspectors equipment deficiencies in the hopes that management would respond to the inspectors' concerns and fix the equipment. Some operators stated they were frustrated at their inability to get some equipment fixed and this had led to them reporting fewer equipment problems.

During discussions with control room operators, the inspectors were told that control room operators had expressed strong reservations about placing the "A" train control room ventilation (VC) fan in service and removing the "B" train VC fan from service for maintenance in May 1996 (see Inspection Report 50-461/96006 for further details). The operators stated that they had a concern with the high vibrations associated with the "A" train fan and recommended fixing it before performing work on the "B" train fan. However, the "A" train fan was started and the "B" train fan was removed from service for maintenance. Subsequently, the "A" train fan was declared inoperable due to high vibration while the "B" train fan was inoperable. This resulted in an avoidable entry into TS 3.0.3, which required a plant shutdown be initiated. The operators further stated that this was an example in which they did not feel that the operations department was controlling plant activities.

Operators also indicated that they had previously voiced concerns regarding their lack of control. The inspectors noted that an operating crew trip report, addressed to the plant operations director and dated June 21, 1996, specifically mentioned this concern. In a "Differences" section, i.e. describing differances between Clinton and the plant visited, the report states that "the operations department was in total control of the plant. When the SS asked for something from an outside department, it was done without question. Everyone on site understood their role in supporting operation of the plant."

The inspectors noted that the support to operators for in-plant implementation of EOPs was weak. Valves required during EOP use were not uniquely identified nor were ladders uniquely identified for EOP use and stationed at the location of use. In addition, several ladder stations had more ladders stored at the station than was listed on the inventory placard which increased fire loading for the area but did not exceed the analyzed fire load.

O1.4 Control of Working Hours

a. Inspection Scope (93802)

The inspectors evaluated the control of working hours for personnel who perform safety-related functions. The inspectors reviewed

- CPS 1001.01, "Control of Working Hours," Rev. 6

and security logs for a sample of individuals covered by the procedure. The inspectors interviewed supervisory personnel in the maintenance and operations departments concerning the procedural requirements and the supervisors' methods for implementing the procedure.

b. Observations and Findings

The inspectors review of the security gate time logs for 11 individuals from April through August 1996 indicated that all had worked within the procedural limits of CPS 1001.01. Interviews with operations and maintenance department supervisors revealed that, with the exception of one individual who was in an acting supervisory position for approximately six months, the supervisors had adequate knowledge and understanding of the procedural requirements. The supervisors also had adequate documentation of working hours to ensure that (1) personnel remained within the working hour limits of the procedure and (2) obtained authorization to exceed the limits in accordance with the procedure requirements.

CPS Technical Specification 5.2.2.e states "Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the Plant Manager, or his designee, to ensure that excessive hours have not been assigned." The inspectors review of CPS 1001.01 revealed that step 8.7 requires at least monthly review of individual overtime records by departmental management. A note in CPS 1001.01 allows a group supervisor's review/approval of bi-monthly Time Control Reports as a means of satisfying these overtime record review requirements. The inspectors interviewed departmental managers and determined most departments were performing a cursory check of bi-monthly time control reports to verify that individuals had not exceeded the working hour limits. The inspectors request to review the methods used in the operations department to meet the TS caused the licensee to identify that a review of individual overtime was not being performed for operations personnel. The failure to perform monthly review of individual overtime for operations personnel who perform safety related functions is an apparent violation of TS 5.2.2.e (EEI 50-461/96011-04).

O1.5 Conclusions on Conduct of Operations

Operations activities were conducted with a lack of rigor. The inspectors considered operator shift turnovers to be generally good, with several noted exceptions. However, short-term turnovers were frequently lax or inadequate and log keeping was weak. The inspectors identified three apparent violations, one for the RO designated to be at the controls leaving the designated area, one for the failure of the LASS to brief a temporary relief of a change in plant conditions, and one for the failure of the operations department to perform the required management review of overtime.

The performance variations among crews in such things as annunciator response and communications indicated a lack of management oversight on the conduct of operations.

Operators on shift did not feel they were controlling activities at the station. The operators appeared to be schedule and cost driven. This view was supported by an OSO and two procedures which provided an atmosphere to operate in accordance with a schedule, operate the unit efficiently, and maximize generation capability. Safe, conservative operation was mentioned; however, safety was usually discussed after efficiency, generation capability or scheduling, when it was mentioned at all. The inspectors were concerned that insufficient emphasis was placed on safe and conservative operations. The comment by one operator that he would have feared for his job if he had taken action to shut down the unit reflects negatively on the safety focus within the operations department.

O2 Operational Status of Facilities and Equipment

O2.1 High Pressure Core Spray System Walkdown

a. Inspection Scope (71707)

The inspectors performed a detailed walkdown of the accessible portions of the HPCS system to evaluate the operational readiness of the system. HPCS was selected because it was identified as the most risk significant system in the Clinton Power Station "Individual Plant Examination Final Report," September 1992. The inspection included verification of system lineup, equipment labelling, integrity of pipe supports, material condition of equipment, and general housekeeping. System lineups and drawings were reviewed for completeness and accuracy. The inspectors also performed a review of the quarterly HPCS pump surveillance test procedure and results:

- CPS 9051.01, "HPCS System Pump Operability," Rev. 35

b. Observations and Findings

The inspectors observed the HPCS components were generally well maintained. Valve positions were in accordance with the system valve lineup checklist,

drawings, the Updated Final Safety Analysis Report (UFSAR) section 6.3.2.2.1. The inspectors review of CPS 9051.01, completed on July 31, 1996, indicated acceptable system performance. The acceptance criteria were met and the inspectors did not identify any deficiencies. The inspectors did observe that the de-clutch lever on motor operated valve (MOV) 1E22F011 had a different orientation than other similar MOVs. The system engineer's review of this issue determined that the torsional spring in the de-clutch mechanism had likely slipped out of its retainer slot. This condition would require an operator to hold the lever in the de-clutch position while turning the valve handwheel if the valve were required to be manually operated; the valve was normally remotely operated. Maintenance work request (MWR) D75050 was initiated to further investigate the de-clutch lever.

c. Conclusions

The HPCS system was in generally good condition with few deficiencies identified.

O3 Operations Procedures and Documentation

O3.1 Requirements for Procedures and Procedure Usage

The inspectors identified a number of concerns with procedure adequacy and procedure usage. These concerns are discussed throughout the report. The requirements for procedures are described in Technical Specification 5.4.1, which requires that written procedures shall be established, implemented and maintained for the applicable activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," states, in part, that the following are typical safety-related activities which should be covered by written procedures: administrative procedures such as procedure adherence and temporary change method, procedure review and approval, shift and relief turnover, log entries, authorities and responsibilities for safe operation and shutdown; general plant operating procedures; and procedures for startup, operation, and shutdown of safety-related BWR systems. For all of the apparent violations, discussed in the following sections, which refer to Technical Specification 5.4.1, the statements of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978 are included.

An additional requirement to follow procedures is imposed upon licensed operators. RO and SRO licenses include a statement "While performing licensed duties, you shall observe the operating procedures and other conditions specified in the facility license which authorizes operation of the facilities." One RO informed the inspectors that he was unaware of this license condition until recently. However, followup interviews with a sample of licensed operators showed this was an isolated case.

O3.2 Procedure Adequacy

a. Inspection Scope (93802)

The inspectors observed operations and reviewed station procedures to determine procedure adequacy. The inspectors reviewed the following documents:

- CPS 1014.01, "Safety Tagging", Rev. 21
- CPS 1019.04, "Foreign Material Exclusion Areas (FMEA)," Rev. 6
- CPS 2800.69, "Feedwater Heater Level Optimization Test, Rev. 0
- CPS 3102.01, "Extraction Steam/Heater Vent and Drains," Rev. 9
- CPS 3506.01C001, "Diesel Generator Operating Log," Rev. 8
- CPS 3317.01, "Fuel Pool Cooling and Cleanup (FC)", Rev. 16
- CPS 9080.01, "Diesel Generator 1A (1B) Operability - Manual and Quick Start Operability," Rev. 40
- CPS 9080.02, "Diesel Generator 1C Operability - Manual and Quick Start Operability," Rev. 37

b. Observations and Findings

Procedure CPS 1014.01 provided instructions for hanging and clearing safety tags, independent verifications, and temporary lifting of tags. The inspectors concluded that the tagout instruction appeared to provide sufficient direction to safely isolate and restore equipment. The inspectors observed safety tagout activities and reviewed the caution tag system. The inspectors considered the tagout program to be effective.

The inspectors identified the operating procedure for the spent fuel pool cooling system was not in agreement with system drawings (see Section E3.1).

During observation of an emergency diesel generator (EDG) operability surveillance the inspectors identified human factors deficiencies in the EDG operating log, CPS 3506.01C001. CPS 3506.01C001 lists nine parameters to be recorded while monitoring the performance of the diesel generator. Although the log provides acceptance limits for each of the parameters the log does not identify the specific gauges to be used for obtaining the readings for eight of the nine parameters. In addition, the parameters identified on the log sheet did not always match the nomenclature used on the gauge label. In the one instance where the specific gauges were identified, the note providing the information was confusing to the operators. This contributed to an initially incorrect decision concerning the gauges to be used for reading the parameter (see Section O3.3).

c. Conclusions

Although some weaknesses were observed, operations department procedures were viewed as adequate.

O3.3 Procedure Adherence

a. Inspection Scope (93802)

The inspectors conducted sustained control room observations, including adherence to procedures. In addition, the inspectors reviewed the following documents:

- CPS 1019.05, Control of Transient Equipment/Materials. Rev. 3
- CPS 3402.01, "Control Room HVAC," Rev. 14
- CPS 3506.01C001, "Diesel Generator Operating Log," Rev. 8
- CPS 9080.01, Diesel Generator 1A(B) Operability - Manual and Quick Start Operability, Rev. 40
- CPS 9443.06, "Drywell Cooler Drain Flow Rate", Rev. 35
- Illinois Power Condition Report, CR No. 1-96-09-163

b. Observations and Findings

The inspectors observed several routine operating evolutions, including lifting of a EDG air compressor tagout and startup of auxiliary building ventilation division. Procedures were utilized and followed in each case directly observed. However, during startup of control room ventilation train "B" on September 18 a non-licensed operator failed to follow CPS 3402.01. During filling of the Control Room Makeup Filter 0VC09SB Moisture Separator Loop Seal, step 8.1.1.1.1.a required the moisture separator drain valve 0VC043B to be closed, step 8.1.1.1.1.b required the loop seal fill valve 0VC096B to be opened for one minute and then reclosed, and step 8.1.1.1.1.c required the moisture separator drain valve 0VC043B to be reopened. While waiting for the loop seal to fill, the operator proceeded with other control room ventilation panel verifications later in the procedure. However, the operator then failed to return these valves to their original positions as required in steps 8.1.1.1.1 b and c. The error was eventually identified during the licensee's investigation of increased inputs to radwaste due to the resulting increased flow into the control building equipment drain sump. The involved operator indicated that work load or fatigue were not factors in the error. The failure to follow the procedure while filling control room ventilation loop seals was an apparent violation of TS 5.4.1 (EEI 50-461/96011-03b). The specific safety significance of the error was minimal, namely increased drain flow. However, the error could have resulted in wetting of the control room charcoal filter. The inspectors also noted that several days after the error, the involved operator had not been made aware of the specific steps and actions that had not been accomplished correctly.

The operators had difficulty performing a local leak rate test because of an inadequate procedure (see Section M3.1). The operators stated they were trying to resolve the procedure problem this time because the NRC was watching. This indicated a lack of procedural adherence for the prior uses of this procedure.

The inspectors observed a number of examples where the conduct of operations in the control room was not in accordance with plant procedures (see Section O1).

The inspectors observed the fuel pool cooling system was not lined up in accordance with procedures (see Section M2.1).

During performance of the EDG 1B quick start operability test the inspectors observed a non-licensed operator complete CPS 3506.01C001. The operator was not certain how to obtain the reading for log entry "Lube Oil Filter dP." and obtained direction from a licensed operator to calculate the value by subtracting two gauge readings at a local engine mounted panel. This direction was incorrect. The procedure did provide the necessary references to gauges to take the required readings. Later the operator stated that the original direction he was given for obtaining "Lube Oil Filter dP" was incorrect. Subsequent discussion with the licensed operator in the control room revealed that at the time he provided the initial (incorrect) direction to calculate the "Lube Oil Filter dP" he was not certain that the method was correct. He subsequently contacted a system expert who informed him of the correct method. In addition, the inspectors noted that the initial direction to calculate the differential pressure as the difference between two gauge readings should have required a Temporary Procedure Deviation (TPD) to be issued prior to proceeding with the surveillance test.

The inspectors observed control and instrumentation technicians perform CPS 9443.06. Although a prerequisite required checking the calibration date of measuring and test equipment, this was not initialled as complete, and data was not recorded by the end of the completion of the work steps. The inspectors questioned this apparent discrepancy. A control and instrumentation department manager stated later that not initialling for a prerequisite was acceptable during the work, and that recording measuring and test equipment data at the conclusion of work was appropriate. The inspectors considered the practice of signing for prerequisites after completion of the work activities was weak, in that problems encountered at the conclusion of work could invalidate the work, and might lead to making improper adjustments to equipment.

c. Conclusions

The inspectors identified one apparent violation of failure to follow CPS procedural requirements and also observed an example of non-conservative decision making by a licensed operator during the conduct of an EDG surveillance test. The inspectors considered these observations indicated a lack of rigor in the conduct of operations.

O3.4 Procedure Change Process

a. Inspection Scope (93802)

The inspectors reviewed the procedure change process, focusing primarily on the backlog and threshold of comments submitted as procedure changes. The inspectors also reviewed:

- PMSO-064, "Comment Control Form (CCF) Processing," Rev. 2

b. Observations and Findings

The CCF was used to submit procedure change recommendations. The process prioritized CCFs as significant, tracked with a number, and unnumbered. The significant CCFs received the highest priority, the numbered CCFs were worked second, and the unnumbered CCFs were placed in a data base until the subject procedure was scheduled for review. The inspectors concluded that PMSO-064 appeared adequate to track procedure change requests.

The CCF backlog was relatively steady at approximately 1200 with about 100 new CCFs each month. Approximately ten CCFs existed from 1992, 40 from 1993, and 80 from 1994. The licensee stated that the provision to not number a CCF was a recent change and that many of the 1200 could have been categorized as unnumbered. No attempt was made to backfit the new system on the backlog.

The inspectors reviewed a sample of approximately 150 CCFs. The inspectors concluded that the CCFs appeared to be categorized appropriately.

c. Conclusions

The inspectors concluded that the procedure change process appeared adequate; however, the inspectors were concerned that the large backlog and corresponding slow response to suggestions could discourage the submittal of CCFs.

O8 Miscellaneous Operations Issues

O8.1 Problem Identification and Correction

a. Inspection Scope (93802)

The inspectors reviewed approximately 275 Condition Reports (CRs) from June, July, and August 1996. The review concentrated on the originating organization and the general level of conditions identified (threshold). The inspectors also discussed the CR system with the program manager.

b. Observations and Findings

The inspectors noted some minor hesitation to write CRs during the control room observations, and one example where a CR was not written when required. Following identification that the RO "at the controls" left the designated area (see Section O1.2), shift management did not write a condition report. CR 1-96-09-142 was written by licensing personnel two days later after inspectors inquired if a CR had been written. In another case, preparation of a CR was carefully considered and fully discussed prior to actually writing the CR. The CR appeared to be submitted to the SS for "approval."

The inspectors' review of CRs showed a few minor items were documented, but generally the CRs identified significant conditions. Additionally, the Nuclear Assessment Division (NAD) prepared approximately 25 percent of the CRs. NAD had initiated about twice the number of CRs the operations department had initiated.

During discussions with the inspector, the licensee reported that an integrated reporting program had just been implemented during August. The move toward the integrated reporting system during September 1996 was voluntary. Several site organizations had started using the integrated reporting system. As development issues are resolved, the licensee expected to complete the move to a fully integrated reporting system during 1997. The licensee reported approximately 200 CRs had been generated during September.

c. Conclusions

The inspectors concluded that the threshold for problem documentation was high for the previous CR system; however, the licensee had started an integrated reporting system and appeared to be improving the reporting program. The inspectors were concerned that NAD had written twice the number of CRs than the operations department had written.

II. Maintenance

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Excessive Packing Leakage from 1FC004A

a. Inspection Scope (93802)

The inspectors accompanied an NEO during his plant tour. During the tour the inspectors had concerns that fuel pool cooling and cleanup (FC) demineralizer bypass flow control valve 1FC004A, had a packing leak of approximately 1000 gallons per day. The inspectors performed a followup inspection to determine the safety significance of the leakage. The inspectors reviewed the following documentation:

- CPS 3317.01, "Fuel Pool Cooling and Cleanup (FC)", Rev. 16
- Illinois Power CR 1-94-01-029, Rev 0
- MWR D59513
- MWR D57635

b. Observations and Findings

On September 18, while accompanying an NEO during his plant tour, the inspectors observed that the NEO had to add approximately 400 gallons of makeup water to the FC surge tank. The inspectors asked the NEO how much water and how often water had to be added to the tank. The NEO responded that approximately 1000

gallons per day had to be added to the tank, in addition to that normally added to compensate for spent fuel pool evaporation. The NEO further stated that the additional makeup was required because of a packing leak on FC demineralizer bypass flow control valve 1FC004A.

Later in the tour, the NEO showed the inspectors the leakage from 1FC004A. The inspectors observed a steady stream down the side of the valve and into a catch basin and subsequently a floor drain. The inspectors also noted that 1FC004A was not located in the train that was in service providing cooling and cleanup.

The inspectors followed up on this issue and developed the following concerns:

- Through discussions with other NEOs and the FC system engineer, the inspectors learned that significant packing leakage had been a problem with 1FC004A for at least two years.

- The inspectors questioned the system engineer if he was sure that the leakage was solely from the packing or did the valve have a body to bonnet leak. The system engineer did not know.

- The inspectors asked the system engineer how often he had walked down the FC system since taking it over earlier in the year. The system engineer indicated that he had been involved in another project and could not recall the last time, if ever, that he walked down the FC system.

- On September 25 the inspectors compared the valve lineup in the control room to that diagramed in Clinton Power Station piping and instrumentation diagram M05-1037, Rev AA. The inspectors determined that the "A" train of the FC system was not isolated in accordance with CPS 3317.01 step 8.1.2.16. The RO then performed step 8.1.2 of CPS 3317.01 to properly line up the system. The LASS then initiated a CR to document the equipment configuration problem.

- On September 26 the inspectors identified that CPS 3317.01 opened both train FC pump inlet valves, 1FC011A and 1FC011B, during normal operations which was contrary to piping and instrumentation drawing (P&ID) M05-1037 which closes the inlet valve for the train not in use. The inspectors discussed this issue with the procedures group supervisor, who at the time did not know the reason for the discrepancy. Subsequently, on September 30, 1996, the licensee initiated CR 1-96-09-209, Rev 0, documenting that a proper review of the UFSAR had not been performed prior to changing the procedure to make it different than described in the P&ID and the UFSAR.

The inspectors concluded that the licensee demonstrated poor attention to detail when addressing the packing leakage from 1FC004A. Specifically, 1FC004A, was allowed to continue leaking at a rate of 1000 gallons per day without verifying that

the system was properly aligned in accordance with CPS 3317.01. This is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03c).

In addition, in approximately 1989, CPS 3317.01 was updated to allow both FC pump inlet valves to be opened during normal operations; however, a safety evaluation was not performed (see Section E3.1).

M2.2 Safety Relief Valve (SRV) Leaks and Acoustic Monitors

a. Inspection Scope (93802)

During control room observations, the inspectors noted that seven main steam SRVs leaked. The leakage was identified by high temperature alarms on the SRV tailpipes during normal operating conditions. The inspectors performed a followup inspection to determine the reason for the leakage, how long this had been occurring, and the licensee's corrective actions. The inspectors reviewed the following documents:

- CPS 5066.05, "ADS or Safety Relief Valve Leaking", Rev. 25
- CPS 5067.08, "SRV Monitoring System Trouble", Rev. 27
- MWR D54733
- MWR D59142
-

b. Observations and Findings

The majority of the leaking SRVs were the result of extended use of SRVs during the April 1996 loss of offsite power event. Additionally, the inspectors noted that two SRVs also had improperly functioning acoustic monitors. The acoustic monitors incorrectly indicated two SRVs were open. One of these two acoustic monitors was associated with one of the seven leaking SRVs. The licensee stated the acoustic monitors are often damaged due to ongoing work, such as scaffolding, in the vicinity of the monitors. The inspectors reviewed completed MWR D54733 which documented extensive work to repair damaged acoustic monitors in 1994 and 1995. MWRs D59142 and D62615 have been issued to perform inspection and repair work of damaged acoustic monitors during the upcoming refueling outage.

Based on discussion with system engineers and a review of alarm response procedures CPS 5066.05 and CPS 5067.08, the inspectors noted that the status of the SRV position can also be determined by the tailpipe temperature alarms. Two setpoints are provided: the 220 F Hi-Alarm is indicative of an SRV leaking whereas the 310 F Hi-Hi Alarm is indicative of an SRV actuation. During normal power operations, the seven leaking SRVs indicated tailpipe temperatures of greater than 220 F but less than 310 F.

The inspectors were concerned that the EOPs required that operators be able to determine the status of SRVs, but present equipment conditions could make that determination difficult. This could adversely impact operator response during an accident or transient.

M2.3 Loose Parts Detection System

a. Inspection Scope (93802)

During control room observations, the inspectors noted that the Loose Parts Detection System (LPDS) was identified as being inoperable. The inspectors performed a followup inspection to determine the history and safety significance associated with this problem. The inspectors reviewed the following documents:

- ORM 2.2.10, "Loose-Part Detection System", Rev. 5

b. Observations and Findings

The licensee's ORM 2.2.10 requires that with one or more loose parts detection system channels inoperable for more than 30 days, a special report must be submitted to the NRC within the following 10 days. In these cases, since the corresponding alarm is in for an extended period of time, a temporary modification was sometimes used to defeat the channel alarms. The inspectors discussed the availability of the LPDS with the engineering personnel. The licensee provided information derived from the licensee's LCO/OR database which showed the system had inoperable channels nine times in 1995 and nine times in 1996. The longest period a channel was inoperable was six months although the typical period was a few days. The licensee had submitted the necessary report to the NRC.

M2.4 Inspector Identified Deficiencies

a. Inspection Scope (93802)

During the performance of plant and control room observations the inspectors noted equipment deficiencies not previously identified by licensee personnel.

b. Observations and Findings

The inspectors observed that the closed cooling water system makeup tank automatic level control valve was isolated and, based on discussions with plant personnel, had not worked for a significant period. However, this condition was not identified by a deficiency tag or work request, the abnormal lineup was not identified in operating procedures or drawings, and the manual actions required to maintain the tank level were not identified on the operator work-around list.

M2.5 Operator Workarounds

a. Inspection Scope (93802)

The inspectors reviewed a list of previously identified operator workarounds and a new definition of operator workarounds defined in OSO-089, "Operator Workarounds," Rev. 1. Also the inspectors reviewed the following procedures to identify any additional workarounds:

- CPS 3001.01, "Approach to Critical," Rev. 16
- CPS 3002.01, "Heatup and Pressurization," Rev. 19
- CPS 3004.01, "Turbine Startup and Generator Synchronization," Rev. 17
- CPS 3005.01, "Unit Power Changes," Rev. 19
- CPS 3006.01, "Unit Shutdown," Rev. 24

b. Observations and Findings

The inspectors determined the previous definition of an operator workaround was broad and this resulted in a high number of identified items, i.e. 268, although a number of these had been closed. The new definition in OSO-089 defined an operator workaround as "an equipment deficiency or design problem that requires compensatory action and impairs the operators' ability to respond to a plant transient in an effective manner. The new definition reduced the number of open operator workarounds to 12. The inspectors concluded the new definition was narrow in that it did not include the potential for these items to initiate transient events.

M2.6 Conclusions on Maintenance and Material Condition of Facilities and Equipment

A number of long-standing equipment issues were identified which hindered facility operations. That these problems were evident with the unit in cold shutdown indicates that these problems are not uncommon. The operating crews were not aggressive in identifying equipment problems and causing existing problems to be resolved in a timely manner. Some equipment problems would individually or collectively impact the operators' ability to respond to accidents or transients. The new definition of an operator workaround had a high threshold in that it only included items that impacted an operator's ability to respond to a transient.

Another element of material condition is the ability of safety equipment to perform as needed. This is assured by performance of surveillance tests. Section M3 discusses some significant concerns with the adequacy of surveillance test procedures. These concerns also reflect on the adequacy of the plant material condition.

M3 Maintenance Procedures and Documentation

M3.1 Local Leak Rate Test Surveillance

a. Inspection Scope (93802)

On September 18 and 19, the inspectors observed portions of the setup and restoration for a local leak rate test (LLRT) of a portion of the main steam system, 1MC045 - main steam line drain containment isolation penetration, in accordance with the following procedure:

- CPS 3101.01, "Main Steam Line Startup" Rev. 10
- CPS 9861.02D019, "LLRT for 1MC045," Rev. 26
- PMSO-043, "Verbal Instructions to Conduct Operations," Rev. 5

b. Observations and Findings

On September 18 the inspectors observed a control room operator clear danger tags and attempt to open 1B21F019, main steam drain and main steam isolation valve (MSIV) bypass outboard isolation valve. The valve did not operate. The LASS immediately noted that the low main condenser vacuum condition was causing a Group I Containment Isolation signal. The Group I isolation signal prevented 1B21F019 from opening. The LASS identified a caution statement in CPS 3101.01 which allowed the opening of 1B21F019; specifically, the operators bypassed the low main condenser vacuum signal and then reset the Group I isolation signal. After the signal was reset, 1B21F019 was successfully opened. On September 19 the licensee completed the LLRT and was restoring the system lineup. The LASS identified that the low main condenser vacuum signal was still bypassed. The inspectors observed a discussion between the LASS and the SS about how to reset the bypass. After some research, the SS determined that selecting reset on the bypass switch would reset the bypass. Since the operators did not have a procedure to reset the bypass signal, the SS determined that verbal approval from the Assistant Director - Plant Operations was required in accordance with PMSO - 043. The LLRT restoration was successfully completed the following shift.

The licensee identified two licensee event reports (LER), 86-024 and 91-001, that described inadvertent Group I isolation due to condenser low vacuum bypass signals. Both LERs involved maintenance activities while the unit was shutdown; however, neither event involved an LLRT. The operators identified these previous events as the reason they were sensitive to bypassing and resetting the Group I isolation signal.

The inspectors noted that this LLRT and others very similar had been done previously and yet the procedure did not contain steps to support bypassing and resetting the Group I isolation signal. The inspectors asked the operators why they were having such difficulty and the operators stated that they were doing the right thing this time (documenting the problem to get the procedure changed) because

the NRC was watching. The inspectors concluded the failure to provide steps in CPS 9861.02D019 regarding the bypassing and resetting of the Group I isolation signal was an apparent violation of TS 5.4.1 (EEI 50-461/96011-03d).

M3.2 Diesel Generator Surveillance

a. Inspection Scope (93802)

On September 21, the inspectors observed EDG 1B testing. Due to inspectors' concerns noted during the EDG 1B observation, the inspectors also reviewed the EDG test procedures for all three EDGs (1A, 1B, and 1C). The inspectors reviewed the following documents:

- CPS 9080.01, "Diesel Generator 1A (1B) Operability - Manual and Quick Start Operability," Rev. 40
- CPS 9080.02, "Diesel Generator 1C Operability - Manual and Quick Start Operability," Rev. 37

b. Observations and Findings

The inspectors identified CPS 9080.01 step 5.11 and CPS 9080.02 step 5.11 caused the operators to prime the fuel oil system until pump discharge pressure stabilized for 30 seconds prior to performing the diesel generator surveillance. The inspectors considered this constituted preconditioning. Initially the licensee's engineering staff stated this did not constitute preconditioning, but later agreed with the inspectors. The procedure revision which incorporated this prerequisite was added during 1994. The inspectors determined the procedures were inadequate in that the procedures caused preconditioning of the EDGs such that the testing did not demonstrate the EDGs would perform satisfactorily in service. This is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03e). The inspectors questioned the operability of the EDGs based on this preconditioning and on September 21 and 22 the licensee conducted surveillance test runs with the preconditioning steps deleted. The EDGs successfully passed the surveillance test.

During observation of the above described surveillance tests performed on September 21 and 22, the inspectors identified a second preconditioning concern. Procedure 9080.01 step 5.5.4 and procedure 9080.02 step 5.5.4 allowed the operators to precondition the EDGs by excessively barring the generators. The step states "Bar over the EDG at least one revolution." Operators were observed on one occasion barring over the EDG about 10 revolutions using a hand held air motor. The barring over was continued while performing steps 5.5.5, 5.5.6, and 5.5.7 of the procedure. The practice of using the air motor had been in effect since about 1991. Turning over the EDG also primes the fuel system via the shaft driven fuel pump. From about 1991 to September 1996 procedures CPS 9080.01 and CPS 9080.02 were inadequate in that the procedures allowed preconditioning of the EDGs such that the testing did not demonstrate the EDGs would perform satisfactorily in service. This is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03f).

During the EDG surveillances, the inspectors noted that the EDG 1B was only declared inoperable during the time it was locked out and slowly rolled over for visual component inspections. The inspectors were concerned that there may be other times during the test that the EDGs would not be able to accept the required safety loads during a design basis accident. During the review of CPS 9080.01, the inspectors did not identify any conditions, outside of those identified in the procedure, that would require EDG 1A or 1B to be declared out-of-service during testing. However, the inspectors did identify a condition in CPS 9080.02 in which EDG 1C should be declared out-of-service during the test but the licensee still considered it operable. EDG 1C is the emergency power supply for HPCS. CPS 9080.02 required EDG 1C to be declared inoperable while the Diesel Engine Control Switch was in the MAINTENANCE position to perform Step 5.5 and its substeps to ensure proper engine starting status. At the completion of Step 5.5, EDG 1C was declared operable. However, Step 5.6, required the operator to "Set DG 1C Governor Speed Droop to 50 percent and check load limit set at 10 (100 percent)." This droop setting corresponded to a speed droop of approximately 3 to 3½ percent. Setting speed droop greater than 0 percent results in the EDG operating at a lower frequency than normal operation. This in turn causes a reduction in HPCS pump speed and flow.

The inspectors discussion with the system engineers showed they did not understand the effect of speed droop on EDG 1C. The inspectors continued to question the licensee on this issue. The licensee then determined that with a speed droop of 3 percent, the HPCS pump was not capable of producing 5010 gpm at a differential pressure of 363 psid, as required by TS SR 3.5.1.4, but only approximately 4860 gpm.

The inspectors concluded that the licensee inappropriately considered EDG 1C operable when a speed droop of approximately 3 percent had been set to accommodate parallelling the EDG to the grid for routine testing. The inspectors further concluded that this practice appears to have been in place since the beginning of plant operations. Because setting a speed droop of approximately 3 percent on EDG 1C affected the ability of the HPCS pump to respond to a design basis accident and the test procedure did not require the diesel generator be declared inoperable while the speed droop was set, the test procedure was inadequate. This is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03g).

M3.3 Diesel Fire Pump Surveillance

a. Inspection Scope (93802)

The inspectors witnessed a surveillance test of the diesel fire pump using procedure:

- CPS 9071.01, "Diesel Driven Fire Pumps Operability Test", Rev. 31

b. Observations and Findings

The inspectors noted that the operator had initialed step 8.1.3.1 as satisfactory yet the needle on the gauge was broken. The inspectors questioned the operator on how he had obtained the reading considering half of the needle was missing. His answer was the procedure only requires that he check for pressure. No specific value or range of acceptance values were stated in the procedure. Since the bottom of the needle was still attached and indicating in a direction that was reading greater than zero the operator concluded that he did have pressure. At the completion of the run the operator wrote an MWR to have the gauge repaired. The lack of a value or range of acceptance values for various engine parameters was brought to the attention of the system engineer. The system engineer was in the process of revising the diesel driven fire pumps surveillance procedures to include acceptable values for engine performance that would be used in making more definitive operability determinations and to trend engine performance over time. The inspectors were satisfied that corrective actions were being taken.

M3.4 Conclusions on Surveillance Procedures

The inspectors concluded that both the LLRT and the EDG procedures were inadequate. The inadequate LLRT procedure caused the operators to select a single step out of an unrelated procedure in order to open 1B21F019 and then rely on verbal directions to complete steps required to restore from the LLRT. The surveillance procedures for all three diesel generators caused preconditioning to occur. The EDG 1C procedure did not provide steps to declare the EDG 1C inoperable while the engine droop was set to 50 percent. The number of surveillances observed was not large; however, a number of procedural problems were observed. This indicates a problem with the adequacy of surveillance procedures.

The inspectors were also concerned that the system engineers did not understand the effect that setting a speed droop on EDG 1C had on the HPCS pump and that in a LOCA concurrent with a LOOP the pump would not be able to meet the flow rate required by TS SR 3.5.1.4.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Main Control Room Ambient Noise and Annunciator Sound Levels

a. Inspection Scope (93802)

During observation of control room activities the inspectors noted that the background noise level in the control room seemed high and that the annunciator horns were not very loud relative to the background noise. At the request of the inspectors, the licensee conducted a sound level survey in the control room. The inspectors also reviewed the control room Upgrade Team Final Report dated

August 17, 1995, and the Clinton UFSAR 7.7.2.23, "Main Control Room Annunciator."

b. Observations and Findings

The results of the sound level survey indicated that the nominal background noise level was 65 dB(A). The 65 dB(A) background noise level was equal to the maximum level recommended for control rooms in NUREG-0700, "Human System Interface Design Review Guidelines." (The Clinton Station UFSAR identified NUREG-0700 as the primary guidance document for the station's Detailed Control Room Design Review.) The practical effect of the ambient noise level was to make normal conversation difficult to hear reliably at distances of approximately 10 feet or more. The noise level required operators to routinely speak in a raised voice which can be fatiguing.

The control room heating, ventilation, and air conditioning (HVAC) system appeared to be the principle contributor to the high ambient noise level. This observation was confirmed by the HVAC system engineer who stated that the system was designed for two control rooms and the current single control room configuration contributed to the high noise level.

Reduction of noise from the control room ventilation was identified as the number one priority in the August 17, 1995, control room Upgrade Team Final Report. During the past year, the licensee had installed carpeting and sound dampening material on the tops of equipment cabinets to reduce the amount of noise reflected from these surfaces. The HVAC system engineer reported that the licensee had plans to install sound dampening materials on the walls of the control room and would evaluate the need for additional noise reduction measures following the installation of that material. The inspectors noted, however, that the licensee had not established a clear goal or acceptance criteria for the noise reduction plan.

The licensee found that the annunciator horn sound level ranged from 78 db(A) at the panel where the horn was mounted to 72 dB(A) at the opposite end of the "at the controls" area. Consequently, the annunciators' signal ranged from 7 - 13 dB(A) above ambient noise levels. NUREG-0700 stated that a signal level of 10 dB(A) above ambient was generally adequate. Although annunciator volume was not 10 dB(A) above background for all parts of the control room, the inspectors (1) perceived minimal masking of the annunciator alarm signal by the ambient noise, and (2) noted during control room observations that the operators consistently responded to the audible alarms and reported no difficulty in hearing the alarms.

c. Conclusions

The control room ambient noise level was a challenge to reliable control room communications and was an operator distraction. This long term material condition issue had not yet been effectively resolved. The lack of a clear goal or objective acceptance criteria for noise reductions was a weakness in the licensee's corrective action plan for this issue. The volume of the annunciators relative to the ambient

noise levels was considered acceptable based upon inspectors' observations, operator performance, and operator statements concerning their ability to detect the annunciator alarm signal.

E2.2 Work Review Board Standards

a. Inspection Scope (93802)

Several operators expressed concern regarding the Work Review Board's (WRB) high priority on economics versus other considerations. The inspectors subsequently reviewed the function of the WRB and evaluated specific WRB decisions.

b. Observations and Findings

The WRB, in existence since July 1996, was tasked with deciding what hardware changes were to be implemented in accordance with the CPS Decision Standard. Both the WRB Charter and CPS Decision Standard addressed safety, although economics was highly emphasized in both. For example, the standard required a significant improvement in nuclear safety for relatively low cost. (Instances where nuclear safety was degraded or which involved regulatory requirements were included in the standard as approvable.)

WRB decisions made to date included approximately 50 proposals approved and 50 rejected. The majority of those approved were based on economic savings although some would also add to safety (e.g. placing main steam line temperature monitors on an uninterruptible power supply (UPS) to prevent unnecessary reactor scrams.) Many of those rejected involved improvements to make jobs easier to perform (e.g. provide a hose reel station for nitrogen charging of accumulators.) Of those rejected, the inspectors identified two with some nuclear safety impact:

- Proposal to power rod information system (RIS) from the computer UPS

  This proposal resulted from an April 9, 1996, event in which switchyard work caused the reserve auxiliary transformer to de-energize. This led to a group I isolation and reactor scram. The rod control system (powered from divisional buses) momentarily lost power. Upon re-energization, operators experienced slow update of the core display including unreliable position indication. Subsequently the core display dimmed and went blank. An unusual event was declared due to the possible failure of rods to insert. The licensee projected the proposal to power RIS from the computer UPS could be accomplished with minimal hardware changes and very low cost. However, despite the low cost, the WRB rejected the proposal since it viewed the increase in safety to not be significant.

- Proposal to upgrade portions of the plant cathodic protection system

  Due to corrosion damage to underground piping at other plants, and discovery of corrosion damage to a portion of fire protection piping at Clinton, the licensee performed a study to determine the acceptability of the cathodic protection system design. The licensee determined through testing that some portions of the system near buildings provided insufficient protection when compared to standard industry criteria in National Association of Corrosion Engineers Standard Recommended Practice RP0169-92, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." (The Clinton UFSAR only provided a brief description of the system but did not commit Clinton to any particular industry standards.) The licensee indicated that no potentially contaminated piping was located in these low protection areas, however fire protection, shutdown service water piping, and diesel generator fuel oil storage tank fill lines were among piping in those areas.

  The cathodic protection proposal for upgrades was rejected twice by the WRB as not cost justified. The justification for rejection indicated that the proposer could not offer probability of failures or consequences and therefore lack of data made evaluation of avoided costs undependable.

In both cases, however, the proposers were not satisfied with the WRB decision and planned to follow a prescribed process of appeal to senior plant management. As the WRB process was only a few months old, no previous proposals had undergone this appeal process. Therefore, a final plant decision had not been made and it was indeterminate how these issues would be resolved. The inspectors identified one additional rejected issue of concern involving an UFSAR design discrepancy for control room chillers (see Section E3.5).

c. Conclusions

Although plant safety was a consideration in WRB decisions, the inspectors identified a very high priority placed on economics. The WRB process was new and the two decisions reviewed in detail had not yet been evaluated in an appeal process. Therefore, the inspectors could not validate any final plant decisions that directly and adversely impacted nuclear safety. However, the WRB process and CPS Decision Standard clearly contributed to a perception among some plant personnel that plant management was highly emphasizing economics beyond other considerations.

E2.3 Temporary Modifications

a. Inspection Scope (93802)

The inspectors reviewed administrative processes utilized by operators for the control and overview of temporary modifications as governed by procedure:

- CPS 1014.03, "Temporary Modifications," Rev. 18

The inspectors also reviewed three temporary modifications in more detail to ascertain the licensee's approach.

b. Observations and Findings

CPS 1014.03 described the controls for the initiation, review, authorization for installation, authorization for release and audit of temporary modifications on equipment and systems. Temporary modifications allowed within the scope of the procedure included:

- lifted electrical leads
- electrical jumpers
- pulled circuit cards, other than annunciator cards

The temporary modification process described controls to limit modifications to less than 30 days. Expected removal dates were included as part of the modification process. Engineering design reviews were required of all temporary modifications to ensure material compatibility, performance of a safety screening, and full safety evaluation, if required. Any post-installation testing or post-removal tests were also required to be documented on the Temporary Modification Permit. Step 8.1.4.6 of CPS 1014.03 required that if a safety screening or safety evaluation identified an impact on operating instructions, the originator was required to assure that the affected instructions were listed in the "Installation" section of the permit under operational restraints and were incorporated into appropriate operating procedures prior to the temporary modification installation. Safety evaluations were required to be approved by the Facility Review Group before the temporary modifications were installed.

Operations support personnel performed weekly reviews to identify those modifications which within seven days would exceed the expected date of removal. Originators of soon to be expired temporary modifications were notified of those overdue and the need for extension if left installed. Quarterly audits of the temporary modification logs were also performed and included field verification of installed temporary modifications.

The inspectors performed a review of the Temporary Modification log to evaluate the log accuracy with respect to accountability of number of modifications installed. Additionally, the inspectors interviewed personnel responsible for performing audits and evaluated the technical adequacy of the safety screenings and safety evaluations considering UFSAR impact. Nine (9) temporary modifications were active at the time of the team's review and the inspectors selected temporary modifications 94-001, 96-026, and 96-032 for detailed review.

The temporary modification log documented the results of the periodic audit reviews performed. Accountability of the installed modifications was evident through control of tracking numbers and periodic audits. No deficiencies were identified during the review of the temporary modification process.

c. Conclusions

Administrative controls were adequate and being implemented by operators and other plant personnel to limit the number and age of active temporary modifications. Sufficient technical review was conducted for the temporary modifications evaluated by the inspectors to assure appropriate safety and licensing aspects were considered prior to implemantation.

E3 Engineering Procedures and Documentation

E3.1 Safety Evaluations

a. Inspection Scope (93802)

During inspectors observations of the operating crews, several concerns were identified which involved licensee 10 CFR 50.59 safety evaluation practices. Followup of these specific issues was not a comprehensive review of the licensee's entire safety evaluation process, but did infer some weaknesses in the licensee's approach.

- CPS 1005.06, "Conduct of Safety Reviews," Rev. 9
- CPS 1406.01, "Annunciator Tracking Program," Rev. 8
- CPS 3317.01, "Fuel Pool Cooling and Cleanup," Rev. 16
- CR 1-96-09-209, Rev. 0

b. Observations and Findings

Inspectors concerns regarding the safety evaluation process included the following examples:

- The inspectors identified that on September 17 operators removed annunciator cards from local condensate panel 1PL03J without performing either a safety evaluation or screening to determine whether a safety evaluation was necessary. Annunciators 5202-2D HI DIFFERENTIAL POLISHER D and 5202-4J HI DIFFERENTIAL RESIN TRAP POLISHER J RESIN TRAP were intentionally disabled in this manner. Operators believed that a pressure switch was causing spurious alarms for the first annunciator and the associated polisher out of service caused the second. Both were causing a local panel trouble alarm in the control room.

  The failure to perform a safety evaluation appeared to result from programmatic deficiencies. CPS 1406.01 was followed by the operators. However, the procedure did not prescribe any necessary UFSAR or related

reviews prior to modifying annunciators. CPS 1005.06 required safety evaluations for disabled annunciators, but for only those disabled for greater than six months. No justification was provided for time limitations on the application of the safety evaluation process to intentional disabling of annunciators.

UFSAR 10.4.6.5 indicated that differential pressure was monitored across each demineralizer vessel and each vessel's discharge resin trap to detect blockage of flow. It also stated that a multipoint annunciator was included in the local panel to alarm abnormal conditions within the cleanup system. Failure to perform a written safety evaluation for this change in the facility as described in the UFSAR is an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-461/96011-05a).

- The inspectors identified that engineers failed to perform a safety evaluation after determining, in August 1995, that the cathodic protection system design did not provide sufficient corrosion protection. A fire protection line leak caused by galvanic corrosion was attributed to insufficient cathodic protection combined with damaged protective pipe wrap from original construction (CR 1-95-08-001). A more comprehensive testing and survey evaluation report of Clinton cathodic protection was performed by contractors for the licensee. Licensee engineers concluded that although the majority of underground steel piping was cathodically protected, some areas near buildings had low pipe to soil potentials compared to the applicable industry standard, National Association of Corrosion Engineers Standard Recommended Practice RP0169-92, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." A subsequent proposal for modifications to correct cathodic protection design deficiencies in these areas had been twice rejected by the WRB (see Section E2.2).

  UFSAR 9.4.5.2 stated that the prevailing soil conditions at the site established the need for cathodic protection, therefore, an impressed-current type cathodic protection system consisting of a d-c power supply, control cabinet, and a number of distributed anode beds would be used. The determination by licensee engineers that insufficient cathodic protection existed in certain areas was a change from the UFSAR description that implied protection of underground piping by a cathodic system was provided. Failure to perform a written safety evaluation for this change in the facility as described in the UFSAR is an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-461/96011-05b).

- On September 17, the inspectors observed that annunciator response books were maintained on top of some of the control room panels. The inspectors determined that a safety evaluation to determine the effect of the books falling onto the control panel either from personnel error or a seismic event had not been conducted. The licensee subsequently initiated CR 1-96-09-209, to document the discrepant condition and removed the books from the control panel.

UFSAR 3.1.2.2.1.0.1 stated that the control room had been designed to meet seismic Category I requirements. Failure to perform a written safety evaluation for this change in the facility as described in the UFSAR is an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-461/96011-05c).

- Plant personnel failed to place sufficient emphasis on determining and ensuring UFSAR conformance for motor operated valve weight discrepancies in the seismic piping design (see Section E3.4). Likewise, plant personnel failed to place sufficient emphasis on evaluating and resolving a control room chiller start UFSAR design discrepancy (see Section E3.5).

- In approximately 1989, CPS 3317.01 was updated to allow both FC pump inlet valves to be opened during normal operations. UFSAR Figure 9.1-4 showed a normal valve lineup with the idle train contrary to the procedure revision. A safety evaluation was not performed for the procedure revision. Failure to perform a written safety evaluation for this change in the facility as described in the UFSAR is an apparent violation of 10 CFR 50.59(b)(1) (EEI 50-461/96011-05d).

- Various operating evolutions directed by engineering plans without written and approved procedures had also not received safety evaluations. This concern is discussed in more detail in Section E3.2 of this report.

- During discussions of these and other issues, the inspectors noted some personnel had a poor understanding of 10 CFR 50.59 safety evaluation requirements (see Section E4).

The potential safety significance of the above examples varied. While disabling the specific annunciators mentioned above would have minimal safety consequence, the programmatic deficiencies could be far more detrimental depending on the annunciator disabled. Issues involving the books on the control room panels and motor actuated valve weight discrepancies could affect proper operation of safety equipment during seismic events. Cathodic protection design deficiencies could affect long term integrity of safety related and other important underground piping systems. Conducting operating evolutions without required procedures, and hence safety evaluations, circumvented normal review processes that existed to prevent adverse safety consequences. The programmatic approach and lack of emphasis on UFSAR discrepant conditions was a broader safety concern.

E3.2 Engineering Guidance to Operations

a. Inspection Scope (93802)

The inspectors learned, through discussions with operating personnel on September 19, that operators were frequently tasked to perform work in accordance with memoranda, usually engineering action plans. The inspectors subsequently reviewed five safety related engineering action plans for appropriate licensee review and operating controls. (One covered multiple evolutions.) The inspectors also

noted an operating standing order that prescribed compensatory actions with insufficient engineering justification.

- OSO - 066, "Watertight Doors," Rev. 0

b. Observations and Findings

The inspectors identified several operating evolutions prescribed by engineering action plans and conducted by the licensee without required procedures:

- On August 1, 1996, the licensee performed a test to verify that there was no negative impact on emergency core cooling systems when cycled condensate (CY) to containment was isolated. When CY was isolated to containment, residual heat removal (RHR) A discharge pressure decreased below the water leg pump (WLP) discharge pressure, and continued to depressurize. The licensee declared RHR A inoperable. Operators checked the WLP lineup. When an operator moved the handwheel of 1E12F085A (RHR A WLP discharge check valve) a partial turn, RHR header pressure immediately started to increase. The licensee concluded the disc was stuck shut and the small amount of motion on the handwheel caused the disc to open. The licensee restored RHR A to operable after completing a fill and vent procedure, approximately 1.25 hours after depressurizing the header. The licensee identified a leaking CY isolation valve had been pressurizing the RHR A header and there was therefore no flow through the WLP discharge check valve. When CY was isolated, with the WLP check valve stuck shut, there was nothing to maintain RHR A header pressure. The licensee had performed the test using a marked-up drawing and log entries. Performing the test for CY isolation impact on RHR without a reviewed and approved procedure is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03h).

- On August 1, 1996, the licensee performed troubleshooting of the WLP check valve, 1E12F085A. A troubleshooting plan was developed by the RHR system engineer that started the RHR A pump, isolated CY to containment, secured the RHR A pump, verified that WLP maintained RHR header pressure, and then restored CY to containment (at the SS's convenience). The troubleshooting plan was submitted by the RHR system engineer and approved by the SS. The system engineer stated that since each step of the troubleshooting plan was part of a different procedure, the troubleshooting plan did not require a safety evaluation. Each of the troubleshooting plan steps individually might have corresponded to a step somewhere in a procedure. The evolution, consisting of a particular sequence of steps with its own overall expected system response, however, was complicated enough to require a specific procedure. Performing the WLP check valve troubleshooting without a reviewed and approved procedure is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03i).

- Since August 2, 1996, the licensee had performed a verification plan weekly to provide assurance that the RHR A WLP check valve continued to

function. This plan isolated CY to containment, vented the CY header, monitored RHR A header pressure to verify that the WLP maintained the appropriate pressure, then restored CY to containment. This verification plan was submitted by the RHR system engineer and approved by the SS. No additional reviews were performed. The WLP check valve had not displayed any symptoms of sticking since the first example. MWRs existed for both the CY isolation valve and the WLP check valve. The licensee had a separate surveillance to verify the WLP check valves would open; however, the verification plan was used to verify proper operation of 1E12F085A. Performing this surveillance activity for the WLP check valve without a reviewed and approved procedure is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03j).

- On May 3, 1995, the licensee performed a test of the control rod drive (CRD) pumps. Seventeen steps of an engineering action plan were performed to determine whether a drop in CRD pressure was due to leaking valves or pump degradation. The action plan was conducted at power, prior to exceeding 40 percent power, and involved shutting discharge check valves, minimum flow valves, and recording data. The affected train was then restored and the other train tested. Performing this CRD pump test without a reviewed and approved procedure is an apparent violation of TS 5.4.1 (EEI 50-461/96011-03k).

The inspectors did not identify any concerns with the three remaining engineering action plans reviewed. Two, concerning solid state trip devices and the fuel building crane, appeared acceptable without specific procedures or safety evaluation screenings. A safety evaluation screening performed for one action plan, concerning standby liquid control suction piping, was appropriate.

The inspectors also noted that OSO - 066 prescribed compensatory actions for inoperable watertight doors with insufficient engineering justification. This OSO delineated required actions for watertight doors which were based upon an engineering letter (Y-81955), dated September 12, 1986. It was not clear that specified actions could be taken under flooding conditions for which the doors were designed. The inspectors examined several of the affected doors and noted that they were in good condition. Therefore, the OSO - 066 guidance was a longer term versus immediate safety concern. The specific inspectors' concerns were as follows:

- For an inoperable inter-divisional shutdown service water (SX) watertight door, operators were instructed to post an individual at the screen house with instructions to open the outside door of the affected SX pump room, should flooding occur. However, the inspectors observed that the outside door for two of the divisional SX pump rooms were maintained chained shut from the inside. The OSO did not indicate where in the screen house the individual should be stationed. The subject doors could not be opened from outside the room. In the event of flooding inside the room, it was not clear that an individual could traverse the room with associated hazards (i.e.

flooding around electrical panels.) As a result of this concern the licensee planned to examine the configuration in the room to determine the continued feasibility of these instructions.

- For the above scenario, it was also not clear whether opening the outer door would prevent flooding from a pipe break in one room from affecting equipment in the adjacent room. The bottom lips of the outer doors were at the same height (about ten inches) as the inter-divisional doors so water would still enter the adjacent room. The bottoms of electrical panels in these rooms were lower than the doors and hence would be partially submerged. Following questioning by the inspectors, the licensee examined the contents of the affected cabinets and determined that the lowest positioned component that could be affected by the water was about ten and a half inches from the ground. The licensee planned to perform calculations to determine if the rising water would be able to reach these components with the outer door open.

- The OSO directed that failure of a seal test did not make a watertight door inoperable. The licensee could not provide any justification for this position.

The basis for the OSO - 066 actions, an engineering letter, provided insufficient supporting evaluation and justification. The concerns regarding OSO-066 compensatory actions are an unresolved item (50-461/96011-06) pending completion of the additional licensee reviews and calculations.

E3.3 Operability Evaluations

a. Inspection Scope (93802)

The inspectors reviewed five operability evaluations (OEs) in detail to ascertain the quality of engineering support in operability decisions. Engineers and operators were interviewed regarding these OEs to determine the suitability of interfaces and focus placed on OEs in both organizations. (Approximately ten other OEs were briefly reviewed, but the subject non-conformances were of such simple nature to require only minimal engineering evaluation.) Two of the OEs are discussed in detail in Sections 3.4 and 3.5.

- CPS 1016.01, "CPS Condition Reports," Rev. 21
- CPS 1405.03, "Evaluating and Tracking Improved Technical Specification Limiting Conditions for Operation/Operations Requirements Manual Operating Requirement Actions," Rev. 0
- CR 1-96-08-023

b. Observations and Findings

In response to the inspectors' request for currently open OEs to review, the licensee experienced difficulty in identifying these. Written OEs were integrated within the larger condition reporting program with no easily distinguishable

attributes to identify an OE was involved. To identify open OEs for the inspectors to review, licensee personnel had to review each individual open condition report documentation package for the presence of an engineering evaluation form and conduct additional discussions with engineering personnel. The exact number of open operability evaluations at Clinton had not been determined by the end of the inspection. The licensee had identified a number to review after two days of searching, but indicated more could be found with additional searching.

The inspectors determined administrative guidance for operability determinations was minimal. In response to a request to provide administrative documents which controlled and provided guidance for operability determinations, inspectors were provided two procedures. Operability determination guidance to operators was minimal (i.e. two short paragraphs) in CPS 1405.03. Although some concepts in support of Generic Letter 91-18, "Information to Licensee's Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and On Operability" guidance were briefly reflected, the vast majority of the guidance was not mentioned. Likewise, CPS 1016.01 prescribed use of an engineering evaluation form to document operability but did not address technical or licensing guidance. No guidance was given on the form itself.

The inspectors identified formal processes did not exist to ensure review, approval, and assurance of completion of OE recommendations. For example, two OEs reviewed by the inspectors had recommendations for the operations department that had not been completed. CR 1-96-08-023 engineering evaluation, identifying potential grease hardening on division 3 switchgear and dated August 6, 1996, recommended that associated switchgear space heaters be tagged out in the de-energized position. This action was to slow possible breaker grease hardening until more long term planned actions could be taken. CR 1-96-09-104 engineering evaluation involved degraded non-safety related power supplies for various transmitters (including a potential for a plant transient and reactor scram on loss of power) and was dated September 17, 1996. This evaluation recommended local undervoltage indication be checked once per shift on the power supplies and that the undervoltage settings be checked and set during the ongoing forced outage. The other non-operations recommendations were completed. Although aware these above actions were not completed, the applicable engineer for these issues was not aware of the reason why. Upon completion of the engineering evaluation, the engineer would brief the current on-shift SS. For actions the engineer felt strongly about, the engineer would follow up and ensure completion. For less important actions, the engineer would just leave the decision to the SS and in these cases did not attempt to follow up to determine final resolution.

Operating personnel had no formal mechanism to evaluate and ensure completion of the OE recommendations. The rationale for acceptance or rejection was not documented. It could not be determined for these examples whether an informed decision had been made or whether the recommendation had been overlooked. The inspectors agreed, that for these specific examples, the recommendations not completed were either not essential or other actions were taken that rendered these actions less important.

The inspectors determined formal processes did not exist to ensure operating personnel were aware and maintained cognizance over conditions which potentially affected operability of their equipment. Open operability evaluations were not kept in a centralized location accessible by operating personnel. Once an operability evaluation was discussed by an engineer with the current on-shift SS, the written evaluation may or may not have been filed in the systems file (i.e. file drawer in the SSs' office where any interesting information might be filed by system.) The decision was left to the SS. While the inspectors noted several OEs in this file drawer, the one open OE searched for by a SS for the inspectors could not be located. Even for those OEs in the drawer, current status would not be indicated.

Furthermore, no formal communication requirements existed to ensure other crews were informed of the OEs, their recommendations, and their status. For the specific open OEs discussed above, the SS could not recall ever seeing the first OE. Although aware of the issue for the second OE, the shift supervisor was not aware there was a formal operability evaluation. The SS was not aware of the recommendations for operations on either of these OEs.

Of the five OEs reviewed by the inspectors in detail, three of them, although more brief and cursory than normally expected, were adequate and addressed pertinent considerations. However, two were viewed as inadequate and are discussed later (see Sections E3.4 and E3.5).

During discussions of this issue with licensee engineers, the inspectors noted unfamiliarity with Generic Letter 91-18 operability and UFSAR conformance expectations. These weaknesses in understanding these expectations are discussed in more detail in Section E4 of this report.

E3.4 Incorrect Motor Operated Valve Weights Utilized In Seismic Analyses

a. Inspection Scope (93802)

Following a review of operability evaluations in general, the inspectors performed a detailed review of condition report 1-96-04-010, dated April 3, 1996, regarding motor operated valve weights greater than analyzed.

b. Observations and Findings

The actual actuator and assembly weights for 46 safety related, seismic category 1 motor operated valves were greater than those utilized in the seismic design calculations. The licensee indicated that the vendor had originally specified incorrect weights for the supplied actuators and assemblies. Subsequent information provided by the vendor indicated actuator weights up to 80 pounds heavier than assumed in the seismic analysis for the valve, and assembly weights (valve and actuator) up to 28 percent (in some cases up to 138 pounds) heavier than previously believed. (The actual piping analysis for each valve may have utilized a higher assembly weight resulting in a smaller difference, but this had not

yet been verified by the licensee.) Systems involved included fuel pool cooling, shutdown service water, suppression pool cleanup, and component cooling water.

Licensee documentation indicated that the increased weight had the potential to affect the seismic qualification of the valves (which also provided an input to Generic Letter 89-10 calculations) and the piping analysis. Increased loads might affect piping support calculations, equipment nozzle calculations, and penetration analysis. Therefore, the error had the potential to affect a large number of safety related calculations and could lead to invalidating the seismic qualification of valves, overloading safety-related piping, or overloading supports or penetrations.

The determination of operability of affected systems was based primarily on engineering judgement. The condition report indicated that a preliminary evaluation had been conducted on April 3, 1996, to address the impact on seismic qualification and operability was not adversely affected. The condition report did not specifically address the rationale behind this determination. A written operability evaluation, dated May 20, 1996, was brief and was not clear as to the rationale utilized.

Further conversations with the licensee seismic engineers, responsible for the written evaluation, indicated that a quantitative determination had been completed for incorrect assembly weights on two inch diameter lines, based upon a particular configuration. Specifically, the two inch line subsystem evaluated consisted of two valves one foot apart. The decreased actual weight of one valve assembly, compared to the weight utilized in the seismic analysis, made up for the increased weight for the other valve. The seismic engineers indicated that they assured similar configurations for the other two inch lines by use of drawings but did not actually verify similar valve weights in the analyses for the counter balancing valve. Furthermore, the engineers were not sure of the specific functions of these valves, so as to have reasonable assurance the weights would be the same. For the incorrect actuator weight for two inch lines, the licensee had determined that the weight in the seismic calculations was only ten pounds less than actual, and therefore a negligible difference.

More importantly, however, the written operability evaluation performed in May utilized engineering judgement to address the assembly and actuator weights for greater than two inch diameter lines and valves. This rationale was based on engineers' familiarity with types and methods of seismic calculations utilized at Clinton, that the additional weight would not be a problem for the larger lines.

Licensee plans and actual progress to date were not within the expectations of Generic Letter 91-18 for resolving this potentially nonconforming condition. The licensee's basis for the written operability evaluation was sufficient for an initial prompt operability call, although in this case the written evaluation reviewed was completed a month and a half after the condition was identified. (In addition, the basis was not well explained in the written document.) Furthermore, the licensee had performed a more rigorous, quantitative evaluation, six months after identification. Licensee engineers indicated that they were not sure whether

current design was within UFSAR seismic design margins. Although a planned refuel outage was less than a month away, the licensee had no plans to make such a determination prior to exiting the refuel outage in mid to late November 1996. The action plan, approved by the licensee's corrective action review board, would not identify and revise affected calculations for under ten inch lines until December 31, 1996, and for greater than ten inch lines until August 1, 1997. Furthermore, the action plan assured resultant design changes were provided by those dates but not necessarily completion of actual in-field modifications. Licensee engineers indicated that they were only about half complete identifying affected calculations for under ten inch lines at the time of the inspection.

Following identification of this issue by the inspectors, the licensee decided to perform some calculations prior to exiting the refuel outage. These calculations would be a bounding analysis for worst case conditions to provide increased assurance of proper design margins and operability.

Furthermore, the condition report's conclusion that the issue was not reportable under 10 CFR 21 was flawed. The basis for this conclusion was that the operability evaluation predicted no adverse affects on piping stress analysis. However, an absolute determination could not be made until calculations were complete. Furthermore, there was no certainty that other plants potentially affected by the vendor error would be bounded by Clinton calculations.

The timeliness of licensee plans and progress to date regarding incorrect motor operated valve actuator and assembly weights in seismic analyses was inadequate and is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI (EEI 50-461/96011-07a).

E3.5 Control Room Chillers

a. Inspection Scope (93802)

During a review of operator workaround documentation, the inspectors questioned an October 1993 licensee engineering evaluation which concerned a UFSAR discrepancy. This was documented in a memorandum to the shift supervisor, U119-93(10-04)-6, "Evaluation of auto-restart of the control room chillers after loss of power - rev 1."

b. Observations and Findings

The inspectors review of the evaluation indicated that the control room ventilation chillers may automatically restart after a loss of offsite power event about 2.5 minutes after the event. However, UFSAR Table 8.3-13 stated the chillers are manually started 20 minutes after the event. The inspectors considered the licensee's engineering evaluation minimally acceptable for an initial prompt operability determination. Although potentially affecting diesel generator loading, the evaluation was not performed by the cognizant diesel generator engineer. The evaluation stated "The fact that the chillers may auto-restart appears to be in

contradiction to the UFSAR table 8.3-13. The affect of this will be evaluated and any corrections and/or desired design changes will be performed as needed. The possible auto-restart of the control room ventilation chillers will not adversely affect diesel generator loading due to the 150 second start time delay and is not an immediate concern."

Licensee plans and actual progress to date were not within the expectations of Generic Letter 91-18 for resolving this UFSAR nonconforming condition. Following the initial determination and despite three years passing in the interim, the licensee had not attempted to supplement the initial OE with a more rigorous, in-depth review of diesel generator loads and related quantitative calculations. Furthermore, despite completion of a refuel outage in the interim, the licensee had not resolved the issue through either a plant modification or completion of a 10 CFR 50.59 safety evaluation (and UFSAR revision) to determine the non-conformance was not an unreviewed safety question. Furthermore, there were no plans to provide such resolution prior to exiting an upcoming refuel outage, less than one month away. The system engineer had submitted a design change to remove the auto-start capability for the control room chillers but this proposal was rejected by the WRB just prior to the inspection period.

The timeliness of licensee plans and progress to date regarding the control room chiller start UFSAR design discrepancy was inadequate and is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI (EEI 50-461/96011-07b). Following identification of this concern by the inspectors, the licensee initiated a condition report and performed a more rigorous, quantitative OE. This new OE, concluding the equipment remained operable, was considered adequate by the inspectors.

E3.6 Conclusions on Engineering Procedures and Documentation

Although the inspection in this area was not a comprehensive review, the inspectors concluded the licensee's approach to determining what constituted a change to the UFSAR and required a written safety evaluation was nonconservative in several cases. The inspectors identified several examples of violations for failing to conduct required safety evaluations. Insufficient emphasis on identification of UFSAR discrepant conditions and ensuring timely resolution was apparent.

The licensee's overview and approach to OEs was not rigorous from virtually every aspect examined by the inspectors: guidance regarding operability and nonconforming condition expectations was not readily accessible and plant personnel understanding was insufficient, operator overview and knowledge of open OEs which could impact equipment was deficient, visibility of OE recommendations and their resolution was lacking, and insufficient emphasis was placed upon evaluation and resolution of nonconforming conditions.

The specific evolutions controlled by engineering action plans fortuitously did not result in any adverse safety consequences. However, in each case, required reviews (e.g. 10 CFR 50.59 safety evaluations) and control processes that existed to prevent adverse safety consequences were circumvented. Routinely conducting

operating evolutions without properly reviewed and approved procedures was a programmatic safety concern.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineering Approach and Understanding

a. Inspection Scope (93802)

Although the primary focus of the inspection was operations, vice engineering, followup of operating issues resulted in several interactions with licensee engineers. This section summarizes several concerns regarding engineers resulting from these interactions.

b. Observations and Findings

Several engineers exhibited a lack of knowledge of the 10 CFR 50.59 safety evaluation process or a non-conservative attitude toward that process. For example, one engineer stated that discovery of a design non-conformance with the UFSAR was not required to be evaluated in accordance with 10 CFR 50.59 if the deficiency was part of the original plant design (i.e. existed from day one.) These weaknesses were evident in several of the apparent violations which involved issues such as annunciator disabling, cathodic protection deficiencies, books on main control room panels, incorrect MOV weights utilized in seismic analyses, and a control room chiller start UFSAR design discrepancy. In most cases, determination whether these issues constituted a UFSAR non-conformance was not considered by licensee personnel. Timely resolution of UFSAR non-conformances was not a priority for the engineers.

The quality of OEs reviewed by the inspectors were generally poor and in some cases deficient. This lack of emphasis on OEs also was evident in apparent violations for the incorrect MOV weights utilized in seismic analyses and the control room chiller start UFSAR design discrepancy. The inspectors' discussions with engineers indicated a lack of knowledge of Generic Letter 91-18 expectations for resolution of nonconforming conditions and operability evaluations.

More specific performance deficiencies were also evident. For example, the diesel generator system engineer knowledge of droop and its affect on the system, and diesel generator preconditioning issues was weak. During a system walkdown with the inspectors, the fuel pool cooling system engineer's knowledge of the system's status was deficient. Apparently, competing responsibilities for other systems had adversely impacted the engineer's cognizance over fuel pool cooling. Engineering justification for contingency actions for inoperable water tight doors was weak, and engineers generally did not exhibit a thorough, questioning attitude during related discussions. The cognizant engineer for two OEs was not familiar with the reasons operating personnel didn't implement all the OE engineering recommendations.

c. Conclusions

Several engineering personnel exhibited knowledge deficiencies and showed a poor approach to resolving deficiencies. Although the sample was too small to make any general conclusions, the inspectors were concerned that engineers were not receiving and understanding suitable performance expectations.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 4, 1996. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. Connell, Vice President
P. Yocum, Manager - Clinton Power Station
D. Thompson, Manager - Nuclear Station Engineering Department
R. Phares, Manager - Nuclear Assessment
J. Palchak, Manager - Nuclear Training and Support
M. Lyon, Director - Assistant Plant/Manager - Operations
D. Antonelli, Director - Plant Support Services
M. Stickney, Supervisor - Regulatory Interface

NRC

A. Beach, Regional Administrator
J. Caldwell, Acting Director, Division of Reactor Projects
H. Clayton, Acting Deputy Director, Division of Reactor Safety
G. Marcus, Project Director

INSPECTION PROCEDURES USED

IP 71707: Plant Operations
IP 93802: Operational Safety Team Inspection

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-461/96011-02	EEI	Operator left the "at the controls" area
50-461/96011-03	EEI	Failure to follow procedures or inadequate procedure
50-461/96011-04	EEI	Failure to perform monthly overtime review
50-461/96011-05	EEI	Failure to perform a safety evaluation
50-461/96011-07	EEI	Inadequate corrective action

Closed

None

Discussed

50-461/96011-01	IFI	Reactivity management issues
50-461/96011-06	URI	Water tight door issues

LIST OF ACRONYMS USED

ADS	Automatic Depressurisation System
CCF	Comment Control Form
CFR	Code of Federal Regulations
CPS	Clinton Power Station
CR	Condition Report
CRD	Control Rod Drive
CY	Cycled Condensate
DB	Decibel
DFP	Diesel Fire Pump
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
FC	Fuel Pool Cooling and Cleanup
FMEA	Foreign Material Exclusion Area
GPM	Gallons Per Minute
HPCS	High Pressure Core Spray
HVAC	Heating Ventilation and Air Conditioning
LASS	Line Assistant Shift Supervisor
LCO	Limiting Condition of Operation
LER	License Event Report
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LPDS	Loose Part Detection System
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
MWR	Maintenance Work Request
NAD	Nuclear Assessment Department
NEO	Nuclear Equipment Operator
ODCM	Offsite Dose Calculation Manual
OE	Operability Evaluation
ORM	Operational Requirements Manual
OSO	Operations Standing Order
PMSO	Plant Manager Standing Order
PSID	Pounds Per Square Inch Differential
RACS	Rod Action Control System
RG	Regulatory Guide
RHR	Residual Heat Removal
RIS	Rod Information System
RO	Reactor Operator
SR	Surveillance Requirement
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SS	Shift Supervisor
STORM	Short Term Operational Requirements Manual
SX	Shutdown Service Water
TPD	Temporary Procedure Deviation
TS	Technical Specification

UFSAR	Updated Final Safety Analysis Report
UPS	Uninterruptible Power Supply
VC	Control Room Ventilation
WLP	Water Leg Pump
WRB	Work Review Board